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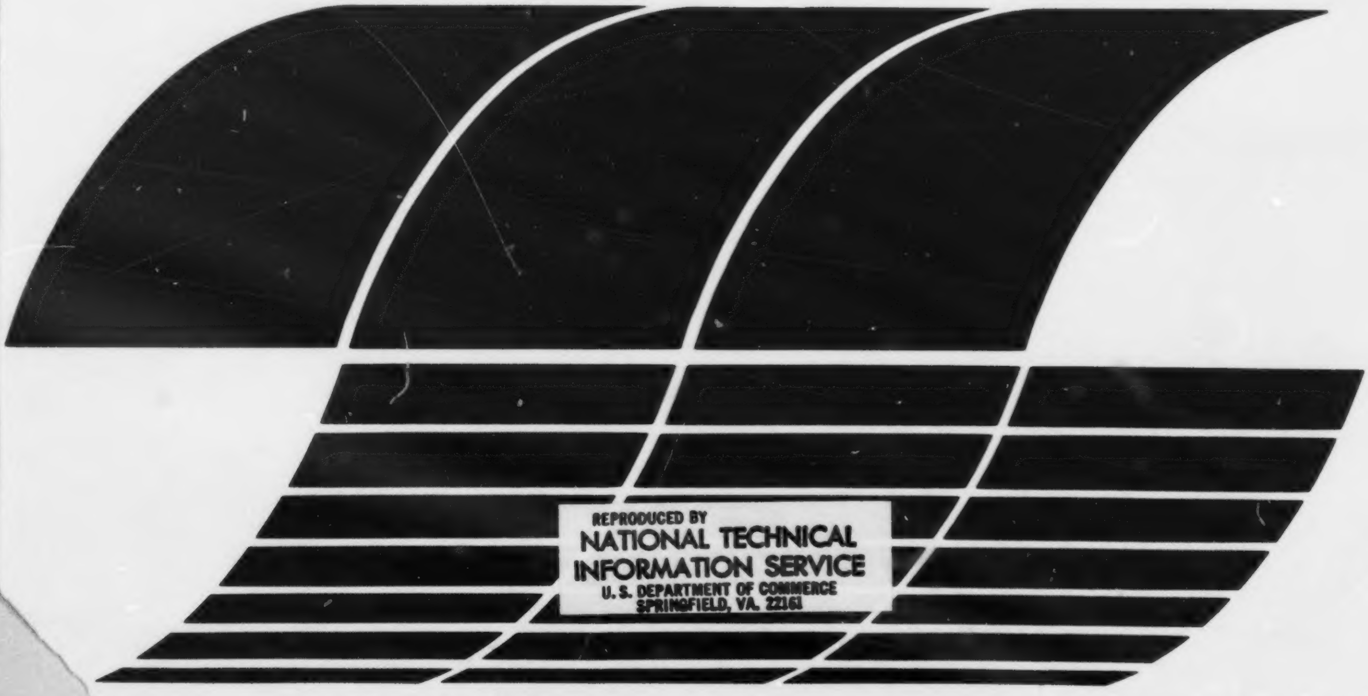

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16. ABSTRACT

A proposed groundwater monitoring methodology for geothermal development specifies a six-step planning and evaluation procedure. Natural geothermal processes and reservoir development are discussed from the point of view of their effects on groundwater. Borehole logging techniques are discussed. Potential problems from chemical and physical plugging and geologic, hydrologic, and reservoir engineering evaluations are listed and discussed.

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FOREWORD

Protection of the environment requires effective regulatory actions that are based on sound technical and scientific information. This information must include the quantitative description and linking of pollutant sources, transport mechanisms, interactions and resulting effects on man and his environment. Because of the complexities involved, assessment of specific pollutants in the environment requires a total systems approach that transcends the media of air, water, and land. The Environmental Monitoring and Support Laboratory, Las Vegas, contributes to the formation and enhancement of a sound monitoring data base for exposure assessment through programs designed to:

- develop and optimize systems and strategies for monitoring pollutants and their impact on the environment
- demonstrate new monitoring systems and technologies by applying them to fulfil special monitoring needs of the Agency's operating programs

This report discusses all the aspects of potential groundwater pollution from geothermal resource development, conversion, and waste disposal and provides guidelines for developing a groundwater monitoring strategy for any such area. It is written for all levels of industry and government where responsibility lies in the areas of groundwater management.

For further information on this subject contact the Monitoring Systems Research and Development Division, Environmental Monitoring and Support Laboratory, Las Vegas, Nevada.

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ABSTRACT

The proposed ground water monitoring methodology for geothermal development specifies a six-step planning and evaluation procedure as follows: (1) define baseline conditions and project development; (2) forecast aquifer conditions; (3) define limits of detection; (4) evaluate ground water and disposal facility monitoring techniques; (5) design monitoring plan and alternatives; (6) implement monitoring plan. A philosophy of prevention is emphasized as an integral, natural and essential component of the monitoring methodology.

Natural geothermal processes and reservoir development are discussed from the point of view of their effects on ground water systems. A liquid-dominated field will produce a far greater volume of effluent than a vapor-dominated field. Most geothermal reservoirs exhibit fracture porosity. They may consist of many separate pockets of fluids at various depths and with varying degrees of hydraulic connection. The relationship between shallow ground water, deep ground water and the geothermal system must be known in order to assess potential degradation.

Borehole logging techniques provide continuous and detailed vertical profiles of rock and fluid properties. These can be used for ground water monitoring in geothermal areas to define baseline conditions, construct wells and monitor observation and injection wells. Well logging techniques cannot be directly applied to the fractured, crystalline environment typical of geothermal reservoirs since the standard calibration and interpretation methods have been developed for the intergranular, sedimentary petroleum environment.

Currently, the most effective disposal method for liquid waste is injecting it into subsurface strata. Injection is also beneficial in that it helps prevent subsidence and facilitates reservoir recharge. Before injection of liquid wastes is initiated, geologic, hydrologic and reservoir engineering evaluations must be conducted. Potential problems may be chemical (e.g., scaling, formation plugging, corrosion) or physical (induced seismicity, hydrofracturing, thermal stress). Actual injection experience is summarized, along with costs and areas of the technology needing research and development.

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SUMMARY

This report discusses all aspects of potential ground water pollution from geothermal resource development, conversion, and waste disposal and proposes guidelines for developing a ground water monitoring plan for any such development. Geothermal processes, borehole logging and injection well technology as they relate to geothermal development and ground water monitoring are also outlined.

Monitoring for geothermal development differs from other types of ground water monitoring in several ways. In addition to geologic and hydrologic factors, the effects that reservoir production and liquid waste disposal will have on the geothermal and cool ground water systems of the area must be considered.

The chemical make-up of geothermal fluids throughout the world varies widely both in number of chemical species and their concentrations. Total dissolved solids may range from about 50 to almost 400,000 parts per million and pH from 2 to 10 units. The fluid characteristics may vary from one reservoir to another, from one well to another in the same reservoir, and over time in the same well. Escape of harmful fluid to usable aquifers or surface water is a prime potential hazard of geothermal development.

Injection is by far the preferred method of geothermal liquid waste disposal. Alternatives to injection are environmentally unacceptable in the United States because of the quantity and chemical composition of the waste fluid. Therefore, the proposed methodology emphasizes monitoring potential ground water degradation due to fluid injection.

GEOTHERMAL PROCESSES

Liquid- or vapor-dominated hydrothermal systems are most likely to be developed. A liquid-dominated system will produce a far greater volume of effluent than a vapor-dominated one. For example, the Wairakei field produces about 200 times as much effluent per unit of electricity as The Geysers.

A geothermal reservoir may consist of many separate pockets of fluids at various depths and with varying degrees of hydraulic connection between them. The relationship between shallow ground water, deep ground water and geothermal water must be known in order to assess potential degradation. A conceptual model to illustrate these relationships would have four main features: a natural heat source, a water supply, a ground water reservoir and a caprock.

For effective waste disposal, the reservoir must be able to accept all of the liquid waste at essentially the same rate it is produced. This rate depends upon porosity and pore geometry of the reservoir rocks, the thickness of the reservoir, the specific weight and viscosity of the fluid, the applied pressure gradient, the number and construction of wells and the overall reservoir flow dynamics. Most geothermal reservoirs exhibit fracture porosity as opposed to intergranular, vesicular or vuggy porosity. A sense of the flow dynamics in a producing reservoir can be developed through analysis of hypothetical reservoir models.

Injection may affect resource recovery by maintaining reservoir pressure, replenishing the geothermal fluid supply, recovering the latent heat content of the reservoir rocks and possibly cooling the geothermal reservoir fluid. In most geothermal systems, resource recovery can be improved by artificial recharge through properly emplaced injection.

THE MONITORING METHODOLOGY

Each potential development area is unique in terms of its activity. Thus, one "monitoring plan" cannot be designed that would apply to all sites. Instead, a general methodology is suggested that can be adapted to the specifics of each site. In applying this methodology a thorough knowledge of geology, hydrology and geochemistry is required for meaningful evaluation and analysis at each site. The six steps in the methodology are outlined below.

1. Define Baseline Conditions and Projected Development

Baseline conditions--those that exist prior to injection--must be established in order to determine hydrologic changes that may occur during injection. These conditions include:

A) chemical characteristics of nongeothermal ground water, geothermal ground water, and surface waters;

B) geology and hydrology of the area;

C) location and well completion data for all wells around the geothermal site; and

D) mechanics and characteristics of the geothermal system.

In addition, it is necessary to estimate production and injection fluid volumes, as well as the chemical and physical changes that the fluid will undergo between production and disposal. The reservoir development plan, established by a reservoir engineer, will specify optimum production and injection rates and well locations. It will provide a basis for estimating how the natural geothermal system will be stressed and how that stress may also influence overlying aquifers. The chemical characteristics of the post-process geothermal fluids must be compared with those of natural geothermal fluid and nongeothermal ground water. Local geologic and hydrologic factors at the site must be defined; e.g. landsliding, which could cause blowouts and consequent ground water pollution, has been a major consideration in planning geothermal facilities at The Geysers.

2. Forecast Aquifer Conditions

Forecasting the interaction between geothermal and nongeothermal aquifers may help avoid potential problems. This analysis will consider: (A) models of the cool ground water and geothermal systems; (B) mechanisms and pathways of potential pollutants; (C) chemical reactions in the aquifers; and (D) effects of alternative developments.

3. Define Limits of Detection

Chemical changes in the ground water will occur in a spatial and temporal matrix. The necessary chemical, spatial and temporal sensitivity of detection in the matrix must be specified for each area. The required sensitivity is mainly a function of:

A) chemical contrast of geothermal and nongeothermal fluids;

B) environmental sensitivity to particular constituents;

C) natural variations in water characteristics;

D) available analytic techniques;

E) hydrologic factors;

F) the relative size of development;

G) characteristics of potential pollutant pathways; and

H) water use and well distribution density in the area.

Analysis of these parameters will aid in determining sampling frequency, distribution and density of sample points, significant chemical and physical parameters, and sampling and analysis methods to be utilized.

4. Evaluate Monitoring Techniques

Ground water monitoring will take place at the disposal facility as well as in the surrounding area. Techniques that may be used are fluid sampling and analysis, well logging, tracers, surface geophysics, pressure, temperature and flow measurements and other special or developmental techniques. All the monitoring techniques, except surface geophysics, involve the use of wells.

Sampling and analysis of the fluid is the most common and usually the only technique used in ground water monitoring. When properly used, applied and interpreted, this technique provides the most direct evidence of chemical changes in the ground water. It will be used in all ground water monitoring plans. The remaining techniques mentioned above may be used in special situations.

Well logging is discussed later in this summary. Under certain conditions, surface geophysical methods may supply information on subsurface structure and ground water flow patterns. Radioactive chemical and dye tracers have been successfully applied to ground water investigations to determine ground water flow paths, aquifer parameters and the vertical and horizontal movement of water within a borehole. The most widely used tracer in ground water study is tritium, a naturally occurring isotope of hydrogen.

5. Design Monitoring Plan and Alternatives

To efficiently detect chemical changes in ground water within the specified chemical, temporal and spatial limits, the monitoring plan must not be constant or static. Some areas will require more frequent sampling; others will require a denser array of sampling points and still others will require different analyses. The greatest risk of waste fluid escape is through or around the outside of the injection well rather than by leakage through permeable confining beds, fractures or unplugged wells; therefore, emphasis will be placed on monitoring in and around injection wells.

The components to be evaluated in arriving at an adequate monitoring plan are: (A) spatial distribution of sample points and sampling frequency; (B) applicable monitoring techniques; (C) chemical and physical parameters; (D) regulatory specifications; and (E) cost versus confidence.

6. Implement Monitoring Plan

Implementing the monitoring plan will involve data collection at specified frequency and locations, and synthesis, interpretation and display of the data. Past data will be reviewed and correlated with new data. As the plan is carried out, the actual needs of the area will become clearer and the plan can be modified for more judicious and efficient monitoring.

APPLICATION OF WELL LOGGING TO GROUND WATER MONITORING IN GEOTHERMAL AREAS

Well logs can play a vital role in a ground water monitoring plan. They can:

A) provide continuous and detailed vertical profiles of rock and fluid properties;

B) help define the baseline conditions and characteristics of potential injection zones, nearby ground water systems and their interrelationship;

C) aid in the construction of injection and observation wells;

D) monitor the condition of the production and injection wells; and

E) aid in monitoring wastewater flow patterns and possible degradation of fresh ground water throughout the monitoring network.

The objectives, operation, analysis and interpretation of well logs in and around geothermal systems are considerably different than those in petroleum systems. Petroleum reservoirs most often occur in relatively soft sedimentary rocks with intergranular porosity at temperatures less than 150°C (300°F) and water saturation less than 100 percent. Geothermal reservoirs usually occur in hard, saturated, fractured, crystalline rocks at relatively high temperatures. Hence, well logging techniques and interpretation may be adequate for geothermal reservoir systems that occur in sedimentary environments, but unfamiliar lithology poses problems. Standard calibration and interpretation techniques are often inadequate for nonsedimentary geothermal reservoirs.

GEOTHERMAL INJECTION TECHNOLOGY

Injection technology is an interdisciplinary field involving geology, hydrology, reservoir engineering, chemistry, material science, mechanical engineering, well drilling and completion technology. Injection wells have been widely used in the petroleum industry for industrial waste injection and in several geothermal fields around the world. Much of the knowledge gained from this experience can be applied to future geothermal development. However, the characteristics of geothermal injection in terms of chemistry, temperature, fluid quantity, depth, flow dynamics and reservoir rock type are often unique.

To conduct a safe and effective geothermal injection program, the physical aspects of the geothermal reservoir and its surroundings must be known. Details of these data and their collection are outlined in the first two steps of the monitoring methodology.

Chemical problems that may be encountered in geothermal injection include: scale deposition in the injection lines and well bore, plugging of the formation around the well and corrosion of pipes in the system. High temperatures and pressures as well as injection of water mixed from different production wells add to the complexity of the chemical problems.

Physical problems in production-injection systems include potential land surface deformation, induced seismicity, hydrofracturing of confining formations and introduction of thermal stress. Injection of spent geothermal fluid into the geothermal reservoir is generally recommended to minimize potential subsidence by maintaining the fluid balance in the reservoir. The possibility of triggering earthquakes by injection can be minimized by not exceeding the original pore pressure of the fluids. Hydrofracturing generally should be avoided.

Reservoir engineering calculations and reservoir modeling are integral preliminary phases of designing the physical injection system. Then the type of pretreatment, the fluid delivery system, the well design and the monitoring operations must be considered. Injection well completion design for hazardous industrial waste disposal is regulated in many states. Applying these regulations to geothermal injection wells will ensure maximum protection of usable subsurface waters.

The cost of a geothermal injection system varies as widely as the size, type, and chemistry of geothermal reservoirs. The total capital cost may vary from approximately $300,000 to $1,000,000.

SECTION 1

INTRODUCTION

Ground water monitoring for geothermal development differs in several ways from monitoring for other purposes. General ground water monitoring would include evaluation of the water chemistry, geology and hydrology of an area. Monitoring for geothermal development would include all these plus knowledge of the type of geothermal system, its flow dynamics under natural conditions, the type and extent of reservoir development and the effects of injecting spent fluids. Hence, an understanding of geothermal processes and injection well technology is required for a viable design and assessment of a geothermal ground water monitoring plan.

The bulk of geothermal waste is hot water, either as spent liquid or steam condensate. In most cases, discharge of this liquid waste to surface or usable ground water bodies would cause chemical and thermal pollution. The preferred and most effective disposal method to alleviate these problems is injecting these wastes into the geothermal aquifer. In addition to minimizing potential water degradation at feasible cost, injection of the waste fluid may minimize induced subsidence and may improve resource recovery. The focus of this report is towards monitoring ground water degradation resulting from injection of spent geothermal fluids.

This report provides a systematic methodology for designing a ground water monitoring plan to detect and predict ground water degradation due to geothermal development. It incorporates a philosophy of prevention as an integral, natural and essential component of monitoring since ground water degradation is often an essentially irreversible process. Ground water degradation is much more difficult to detect and trace than surface water degradation. When it is possible, mitigation of ground water degradation is difficult and expensive.

Utilizing this proposed methodology prior to injection and enforcing rigid specifications for injection well construction will greatly minimize the chances for ground water degradation. In applying the methodology, well logging can provide valuable contributions to well construction, design, baseline data acquisition, injection, well monitoring, and observation well monitoring.

Case histories of ground water contamination due to injection of waste show that many of them could have been prevented by appropriate study and facility design beforehand. If the initial study shows that the injected fluid may interfere with any useful ground water aquifer, then the design, location and flow rates of the offending wells must be modified before production and injection begin.

Recent state and Federal regulations regarding the introduction of fluids into ground water systems specify extensive planning and analysis. The Safe Drinking Water Act (SDWA) of 1974 authorizes the U.S. Environmental Protection Agency (EPA) to protect ground water. Several states have enacted statutes requiring reports of various parameters before permits are issued for deep-well disposal systems. These statutes and policies, along with numerous discussions in the literature, provide a sound basis for the development of a comprehensive and integrated approach to ground water monitoring applicable to geothermal injection well systems. This report suggests such an approach based on previous work and policies and proposes application of borehole logging technology. The resulting methodology will provide a procedure for detecting and preventing ground water degradation due to geothermal development.

1.1 REPORT ORGANIZATION AND PREPARATION

Section 1 of the report discusses related studies on ground water monitoring and injection, ground water monitoring philosophies, and terminology used in this report.

Section 2 provides an overview of geothermal occurrences and processes, with emphasis on how they may relate to and affect ground water flow. This overview is provided by discussions of the types of geothermal systems, geothermal system models, geothermal reservoir engineering and resource recovery as it relates to injection.

Section 3 of the report presents the monitoring methodology itself. The six steps of the procedure are: (1) define baseline conditions and projected development, (2) forecast aquifer conditions, (3) define limits of detection, (4) evaluate monitoring techniques, (5) design monitoring plan and alternatives, and (6) implement monitoring plan. Each of these steps is detailed in the section.

Section 4 covers the application of well logging to ground water monitoring in geothermal environments. It surveys the available logging techniques, their application and limitations in the geothermal environment, their cost and description of logs that would be applicable to each phase of the methodology.

Section 5 provides an overview of geothermal injection well technology. It includes discussion of characteristics of geothermal injection, injection technology development in other industries, chemical and physical problems associated with injection, injection system design, geothermal case histories and research needs.

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1.2 RELATED STUDIES

Many of the specific elements, (e.g., establishing geologic and hydrologic conditions, field sampling techniques or mathematical modeling) are tasks that are outside the scope of this study and are only discussed summarily here, presuming the reader has this background knowledge or will refer to the cited references:

Several studies have been published in areas directly related to the present study. These include five EPA reports on "Monitoring Ground Water Quality":

- "Monitoring Methodology" (Todd, et al. 1976) outlines a step-by-step general ground water monitoring procedure and discusses ground water quality. It emphasizes surface sources of ground water degradation.

- "Methods and Costs" (Everett, et al. 1976) discusses methods of estimating current costs for monitoring at the land surface, in the vadose zone and in the zone of saturation, and for sample analysis.

- "Data Management" (Hampton, 1976) is concerned with the types of information to be managed (such as geologic, hydrologic, water quality, temporal and spatial) and discusses the collection, communication, storage, processing and retrieval of this information, along with possible applications of existing data management systems.

- "Illustrative Examples" (Tinlin, 1976) covers ground water pollution case histories and evaluation of monitoring techniques for brine disposal in Arkansas, plotting waste contamination in New York, landfill leachate contamination in Connecticut, an oxidation pond in Arizona, and multiple source nitrate pollution in California. It also applies the monitoring methodology of Todd, et al. (1976) to examples for agricultural return flow, a septic tank, a percolation pond and a solid waste landfill.

- "Economic Framework and Principles" (Crouch, et al. 1976) covers the legal and institutional aspects of ground water pollution. Economic issues of ground water monitoring are discussed within a framework of an actual hydrogeologic example and the economic principles are analyzed.

Other relevant documents published by EPA include:

- "Polluted Ground Water - Some Causes, Effects, Controls and Monitoring" (TEMPO, 1973) discusses: ground water quality and pollution, institutional and legal aspects, salt water intrusion, pollution from diversion of flow and direct disposal of pollutants from industrial injection and other types of wells, surface ponding, septic systems, spraying, stream beds, landfills, tank or pipeline leakage, and percolation from surface waters.

The following documents are particularly relevant to this report since the preferred waste disposal method for geothermal developments is injection of spent fluids.

- "Monitoring Disposal Well Systems" (Warner, 1975) includes discussion of the subsurface environment, acquisition of subsurface data, prediction of aquifer response and surveillance of operating wells.

- "Review and Assessment of Deep Well Injection of Hazardous Waste" (Reeder, et al. 1977) discusses geologic, engineering, chemical and microbiological aspects of deep well injection of hazardous industrial waste, as well as ground water use and monitoring. Additional topics are characterization of waste, injection well inventory and case histories, deep well injection research projects, economics of deep well systems and legal and regulatory considerations.

- "An Introduction to the Technology of Subsurface Wastewater Injection" (Warner and Lehr, 1977) a general treatise on all aspects of injection.

Many other relevant references are cited throughout the report.

1.3 GROUND WATER MONITORING PHILOSOPHIES

Ground water monitoring philosophies can run the gamut from no monitoring to a detailed, complex and comprehensive program. Most plans will fall between these two extremes.

Ground water monitoring is conceptually fairly straightforward; however, the application and interpretation may be quite complicated. In a simplified example (Fig. 1.1), a fluid is introduced into an aquifer at Point A and monitored at Points 1, 2, 3, 4 and 5. Degraded water is detected in Wells 1 and 4. This evidence is combined with information about direction and rate of natural ground water flow to estimate the location of the degraded water front. Most field situations are not so simple. Some problems which may arise include the erratic concentration of fluid constituents in the observation wells; differential make-up of the subsurface (lensing strata, buried stream channels or faults may alter flow rates in certain directions); unforeseen natural temporal and spatial changes in water characteristics; interaction of the geothermal system with cooler ground water flow; interaquifer degradation from poorly constructed wells. Complications such as these make rigorous analysis and planning necessary to mitigate potential ground water degradation.

Monitoring was not prevalent before the current era of environmental consciousness and regulation. This is still the case in areas where regulatory constraints have not yet been formulated or are not being enforced, or where potential ground water degradation has not been considered. This "philosophy" essentially disregards the effects of disposal on the ground water system.

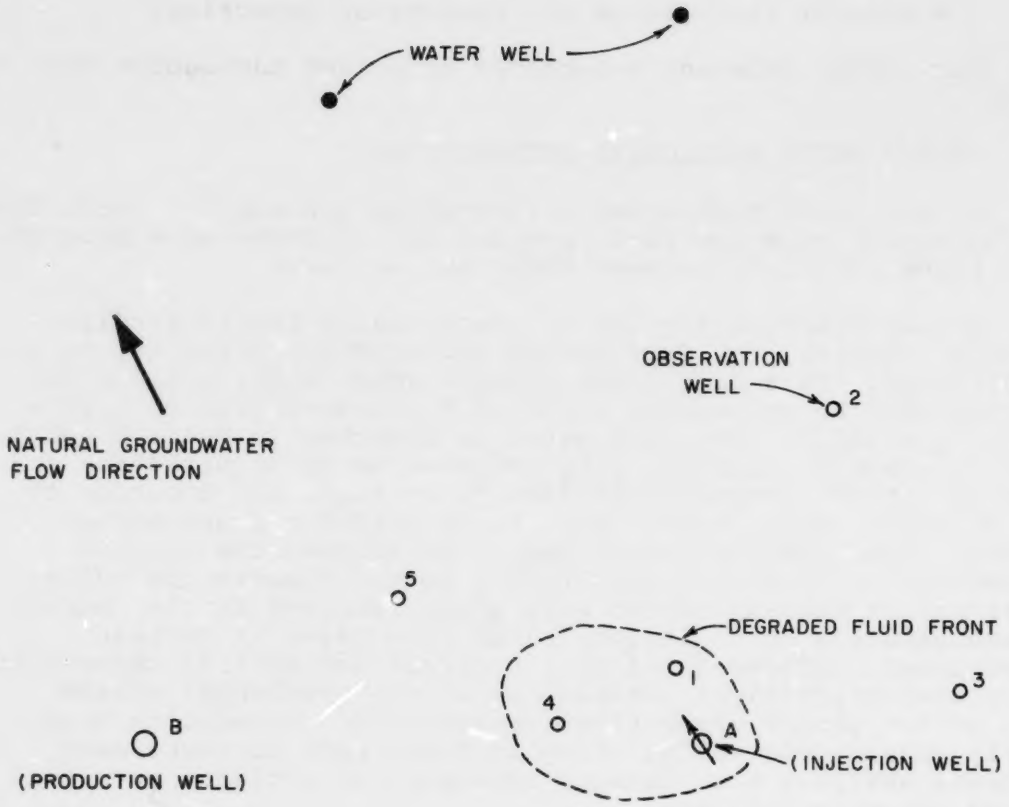
WATER WELL
OBSERVATION WELL
2
NATURAL GROUNDWATER FLOW DIRECTION
5
DEGRADED FLUID FRONT
1
3
4
B
A
(INJECTION WELL)
(PRODUCTION WELL)

Figure 1.1 Schematic diagram of areal spread of degraded water.

Active monitoring can be divided into three aspects:

1) detection,

2) prediction, and

3) prevention.

The goal of detective monitoring is to discover ground water degradation if it occurs. Predictive monitoring proposes to predict degradation before it occurs, or to predict its advance once it has started. Preventive monitoring proposes to prevent degradation. These aspects are discussed in more detail below.

A detective monitoring plan includes an array of monitoring points which are sampled at specified intervals after the degraded water is introduced into the ground. The samples are analyzed chemically to detect the areal or spatial pattern and rate of spread of a degraded water front. The sensitivity of such a system depends on the density and distribution of monitoring points and the sampling intervals, and will increase in proportion to the number of sample points, frequency of sampling, and thoroughness of the vertical and horizontal distribution of monitoring points.

Using inferences based on geologic and hydrologic data and adequate planning, reliable detection limits may be provided. This type of plan might use existing wells and perforated intervals. Additional observation wells may be drilled or existing wells might be reperforated where necessary. The geologic and hydrologic information will permit the extrapolation of ground water flow data to areas without sample points. Estimated flow rates and paths will provide a basis for deciding on a reasonable sample interval.

A predictive monitoring plan involves more detailed geologic, hydrologic, and geochemical investigations. The analysis will most likely employ a conceptual or mathematical model and the results may be used to estimate the potential extent and rate of dispersion of degraded water into the ground water system. This investigation and prediction often occurs after some degraded water has been detected in an aquifer. Then it is considered imperative to understand how the degraded water got there, where it will go next, and how long it will take to get there.

A preventive monitoring plan is similar in many respects to the predictive plan. However, the disposal facility will be designed and constructed to prevent escape of degraded fluid (i.e., well design in Section 3.4 and surface facilities in Section 3.1). Additionally, the data gathering, analysis, interpretation and prediction all take place prior to introduction of degraded water into the ground water system. If the prediction is that the wastewater will be unacceptably dispersed into the ground water system, the proposed disposal plan will be modified to produce acceptable dispersion rates and patterns.

These three aspects of monitoring are not mutually exclusive. An adequate monitoring plan will incorporate each of them. The interrelationship between these aspects and the monitoring methodology is illustrated in Figs. 1.2 and 1.3.

Past monitoring plans have tended to be primarily detective. Current plans for significant projects also incorporate predictive and preventive aspects to varying degrees. The ground water monitoring methodology proposed here is based on this concept of an integrated approach.

1.4 TERMINOLOGY

Certain technical terms used in this report have been used with different nuances of definition. To minimize misunderstandings due to terminology, these terms, as they are used in this report, are defined below.

"Monitoring methodology"--describes the process, or set of considerations, evaluations and steps, that is used to develop a "monitoring plan". So, the "methodology" is the general approach.

"Monitoring plan"--the site-specific detailed program for predicting, detecting and preventing ground water degradation at a particular geothermal development.

"Degradation"--an increase in the concentration of dissolved or suspended materials in any water. It is used in preference to other terms such as "contamination" or "pollution" which imply a judgment on usability. Water may be degraded to a point at which it is not usable for some purposes and still usable for others. For example, a water may contain some elements in concentrations toxic to humans, but may be suitable for some industrial process; or a water with more than one or two ppm boron may not be used for irrigation, but may be potable.

"Injection"--emplacement of a fluid in the ground through an injection well. The geothermal industry has used the term "reinjection" for this process, but this implies that the fluid is being injected again, which is not necessarily so. The term disposal well is avoided since it implies that the only function of the well is for disposal.

Injection well technology is an interdisciplinary field. Consequently, the somewhat different connotations that

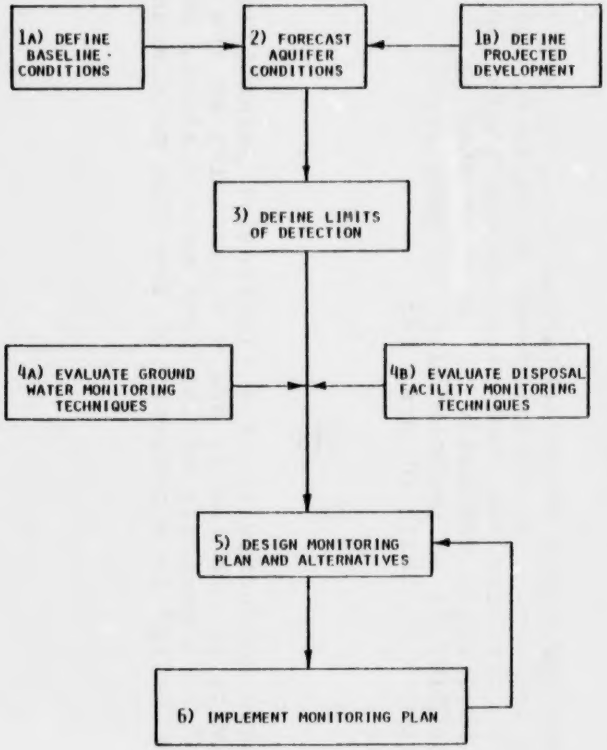
1A) DEFINE BASELINE CONDITIONS
2) FORECAST AQUIFER CONDITIONS
1B) DEFINE PROJECTED DEVELOPMENT
3) DEFINE LIMITS OF DETECTION
4A) EVALUATE GROUND WATER MONITORING TECHNIQUES
4B) EVALUATE DISPOSAL FACILITY MONITORING TECHNIQUES
5) DESIGN MONITORING PLAN AND ALTERNATIVES
6) IMPLEMENT MONITORING PLAN

Figure 1.2 Flow chart of the monitoring methodology.

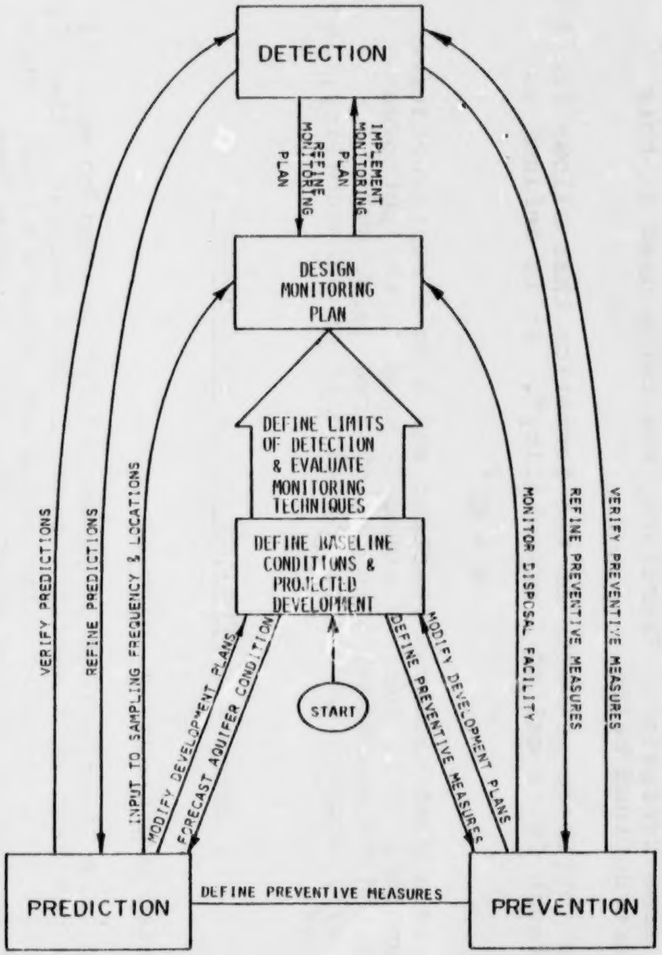
DETECTION
REFINE MONITORING PLAN
IMPLEMENT MONITORING PLAN
DESIGN MONITORING PLAN
DEFINE LIMITS OF DETECTION & EVALUATE MONITORING TECHNIQUES
DEFINE BASELINE CONDITIONS & PROJECTED DEVELOPMENT
START
VERIFY PREDICTIONS
REFINE PREDICTIONS
INPUT TO SAMPLING FREQUENCY & LOCATIONS
MODIFY DEVELOPMENT PLANS
FORECAST AQUIFER CONDITION
DEFINE PREVENTIVE MEASURES
MODIFY DEVELOPMENT PLANS
MONITOR DISPOSAL FACILITY
REFINE PREVENTIVE MEASURES
VERIFY PREVENTIVE MEASURES
PREDICTION
DEFINE PREVENTIVE MEASURES
PREVENTION

Figure 1.3 The interrelationship of detective, predictive and preventive aspects of monitoring and the monitoring methodology.

permeability terms have developed in these related fields may lead to some confusion. Therefore, the terms used in this report are defined below.

The intrinsic property of the formation that allows fluid to flow through it is called "permeability". It is defined as:

$$k = Cd^2$$

where C is a dimensionless constant and d is a representative pore diameter. This term is commonly used in the petroleum industry and is expressed in units of area (e.g. cm^2). The "darcy", adopted as the practical unit of permeability, is defined as:

$$1 \text{ darcy} = \frac{1 \text{ centipoise} \times 1 \text{ cm}^3/\text{sec}/\text{cm}^2}{1 \text{ atm}/1 \text{ cm}}$$

and is also expressed in units of area.

The term "coefficient of permeability" is used to express the flow property of a specific fluid flowing through a specific rock matrix at a specific temperature and pressure head. This term, often used in ground water hydrology, is sometimes inadvertently referred to simply as "permeability" ergo the confusion. The coefficient of permeability (K), or hydraulic conductivity, originally defined in 1856 by Darcy, is:

$$K = \frac{Q}{A(dh/dL)}$$

Q is the flow rate through a cross-sectional area, A, and (dh/dL) is the hydraulic gradient. It is expressed in units of velocity (e.g. cm/sec). To minimize the confusion between these two terms, the term "hydraulic conductivity" will be used in reference to "coefficient of permeability" in this report. The relation converting K to units of area is:

$$K = \frac{kg}{v}$$

where K = hydraulic conductivity, k = (intrinsic) permeability, g = specific gravity of the fluid, and v = viscosity of the fluid. So "permeability" is a property of the rock matrix alone, while "hydraulic conductivity" is a property of the rock matrix and the fluid.

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SECTION 2

GEOTHERMAL PROCESSES

Three general classes of geothermal resources are commonly recognized: hydrothermal convection systems, hot igneous systems, and conduction-dominated areas. The great majority of currently utilized geothermal resources are hydrothermal convection systems, which are discussed in detail below. Hot igneous systems include partially molten magma masses and "hot dry rocks". Conduction-dominated areas include all remaining areas of the earth's crust, especially those with somewhat higher than normal temperature gradients (White and Williams, 1975).

Problems in utilization of hot igneous and conduction-dominated systems involve lack of technology to efficiently extract the heat. An experiment is underway at Los Alamos Scientific Laboratory (LASL), New Mexico, to extract energy from the nearby hot dry rock system. Cool water is injected in one well, heats as it flows through a hydrofractured hot igneous mass, and is pumped to the surface through a second well. If this heat recovery technology is successfully developed, it will produce a highly controlled geothermal ground water flow system with unique flow dynamics, boundary conditions and fluid chemistry.

Because of the large volumes of rock involved, the conduction-dominated areas contain the largest portion of heat in the earth's crust, but at economically accessible depths the temperatures are comparatively low. The geopressured resource of the Gulf Coast is of particular interest in this category since three forms of potential energy may be recovered--heat and mechanical energy from the hot, overpressured pore fluids, and dissolved methane.

Hydrothermal convection systems are usually divided into two classes: those dominated by hot water and those dominated by vapor (White, et al. 1971). Both exist as "reservoirs," i.e., a body of stored fluid in the pore space of a subsurface rock formation. A geothermal reservoir may consist of many separate pockets of interstitial pore fluids at various depths with varying degrees of hydraulic connection between. These individual pockets are traditionally considered reservoirs in the oil and gas industry. Most geothermal resources have not been sufficiently developed to define these individual pockets and most of the fluid produced is a mixture of fluid from several pockets.

In a typical hot water system, liquid is encountered at all depths. It will produce "wet steam", i.e. steam coexisting with hot water. A vapor-dominated reservoir produces "dry" steam with little or no boiling water at the surface. Varying amounts of noncondensible gases, consisting of carbon dioxide, hydrogen sulfide, methane, nitrogen and others, may be associated with each type of system.

2.1 HOT WATER SYSTEMS

Hot water systems are apparently far more abundant than vapor-dominated ones. Pressure caused by the buoyant force of thermally heated water causes hot water to flow upwards and to convect when its flow to the surface is impeded.

The temperature of known hot water systems varies greatly depending upon the proximity of the water reservoir to the heat source, the temperature and size of the heat source, the heat transfer mechanism and other factors. Temperature generally increases with depth, although not in a predictable manner. The highest recorded temperature of liquid-dominated geothermal systems is about 370°C (698°F) at the Salton Sea field in the Imperial Valley, California and at Cerro Prieto, Mexico. Temperatures as high as 340°C (644°F) have been recorded in a well recently drilled in Puna, Hawaii. Most systems, however, have lower temperatures. The Wairakei field in New Zealand has a reservoir temperature of 240 to 260°C (464 to 500°F). Currently 150°C (300°F) is considered the minimum feasible temperature for economic electric power generation.

The fluid in liquid-dominated geothermal fields varies from highly acid to alkaline. The chief salts produced are sodium chloride, calcium chloride, magnesium chloride, calcium carbonate, sulfates and silica. Salinity generally ranges from 0.1 to 1.5% solids. However, in very rare cases, such as the wells of the Salton Sea field, California, levels of dissolved solids may rise as high as 35%. The chemistry of geothermal fluids is discussed in more detail in Section 2.5.1.

In a typical hot water system, only part of the fluid will be produced as steam, the rest as hot water. About 20% of the total mass will flash to steam in a well with a bottom hole temperature of 250°C (482°F) and a wellhead pressure of 0.34 MPa (50 psig). The rest of the fluid will be separated off as superheated water at a temperature of about 140°C (284°F). These are typical conditions for the Wairakei and Cerro Prieto wells.

The steam is conducted to the power plant. The water, which is slightly superheated (relative to atmospheric pressure), may be allowed to cool to boiling at atmospheric pressure and then disposed of. Alternatively, the water may be conducted to another separator for a second flash cycle, during which the lower pressure steam will separate from the boiling water. This steam may then be conducted to a second stage of power production that uses a lower-pressure turbogenerator.

2.2 VAPOR-DOMINATED SYSTEMS

Vapor-dominated systems are quite rare. The oldest known one is in Larderello, Italy. The largest known system is The Geysers field in northern California.

Practically all of the well output in a "dry steam" field may be directly transmitted to the power plant after minor cleaning of the steam. When the content of noncondensible gases is high, their extraction before the steam is introduced into turbines improves the efficiency of condensing-type turbines.

"Dry steam" reservoirs probably contain some hot water as well as steam. High-temperature water may convert into steam in the rocks when the ambient pressure is reduced by venting. The initial steam production reduces pressure in the surrounding fluid. Pressure reduction below the boiling point will allow conversion of liquid into dry steam in the rock pore space. Because of the thermodynamic properties of water, vapor-dominated reservoirs characteristically exhibit a narrow temperature range, typically about 200° to 240°C (390° to 460°F).

2.3 GEOTHERMAL SYSTEM MODELS

The relationship between shallow ground water, deep ground water and geothermal water must be known in order to assess the potential degradation of ground water due to geothermal development. This includes comprehension of the mechanisms of recharge and discharge, heat transfer, fluid flow direction and rate, water chemistry, geometry of ground water reservoirs and aquifers, field boundaries and the rate and location of fluid extraction and injection. Available data will generally be insufficient. Therefore, to understand the geothermal aspects of the ground water system, it is necessary to utilize a conceptual model consistent with the data available. Such a model, from basic characteristics to general types to a specific Imperial Valley geothermal field, is described below. As data are collected and analyzed, the model should be improved to better represent conditions in a specific reservoir.

2.3.1 Basic Model

A basic model of a geothermal system contains four features. They are: natural heat source, water supply, ground water reservoir and caprock (Facca, 1973, p. 62). The heat source in most cases would be of magmatic origin. The water supply would have to be sufficient to saturate and replenish the permeable rock or aquifer. The caprock would seal the system to allow convection in the aquifer or at least trap the water long enough for it to be heated (Figs. 2.1 and 2.2). In this general model, ground water in the permeable aquifer is heated by conductive heat flow through the bedrock from the magmatic source. Since heated water rises, it starts convective currents within the aquifer beneath the confining caprock. This heated water may escape through the caprock via fractures or wells. Fig. 2.3 shows temperature versus depth plots which are typical of hydrothermal convection systems. The sharp decrease in temperature gradient as it enters the hydrothermal convective cell beneath the caprock is diagnostic of such cells.

The rate of recharge is delicately balanced against the pressure differential between the reservoir and its surrounding area. Evidence from repeat gravity surveys across the Wairakei geothermal field in New Zealand (Hunt, 1970) suggests that at present production levels, the recharge of that liquid-dominated system is at least one-third the rate of extraction. This conclusion is based upon calculation of the expected change in the gravitational attraction of the earth across the field if no recharge took place, in comparison with the actually observed change.

A very large quantity of water flows through a geothermal system over its life. Ellis (1966) has estimated that the geothermal fluids in the Wairakei system in New Zealand have been replaced several tens of times. Meidav, et al. (1975) have estimated that the amount of geothermal water that has flowed through the East Mesa geothermal system in the Imperial Valley is on the order of 9×10^{15} kg (1×10^{13} tons). Such a quantity represents a flow of water hundreds of times greater in volume than the total pore space in that reservoir. Even such geothermal systems as that at Larderello or The Geysers, have a large inflow of water, despite the effective seal that such systems must possess. Oxygen and hydrogen isotope studies suggest that the level of recharge of both systems must be about 10% or more of the current rate of production of steam. In The Geysers case, it is quite likely that an increase in production would result in an increase in recharge.

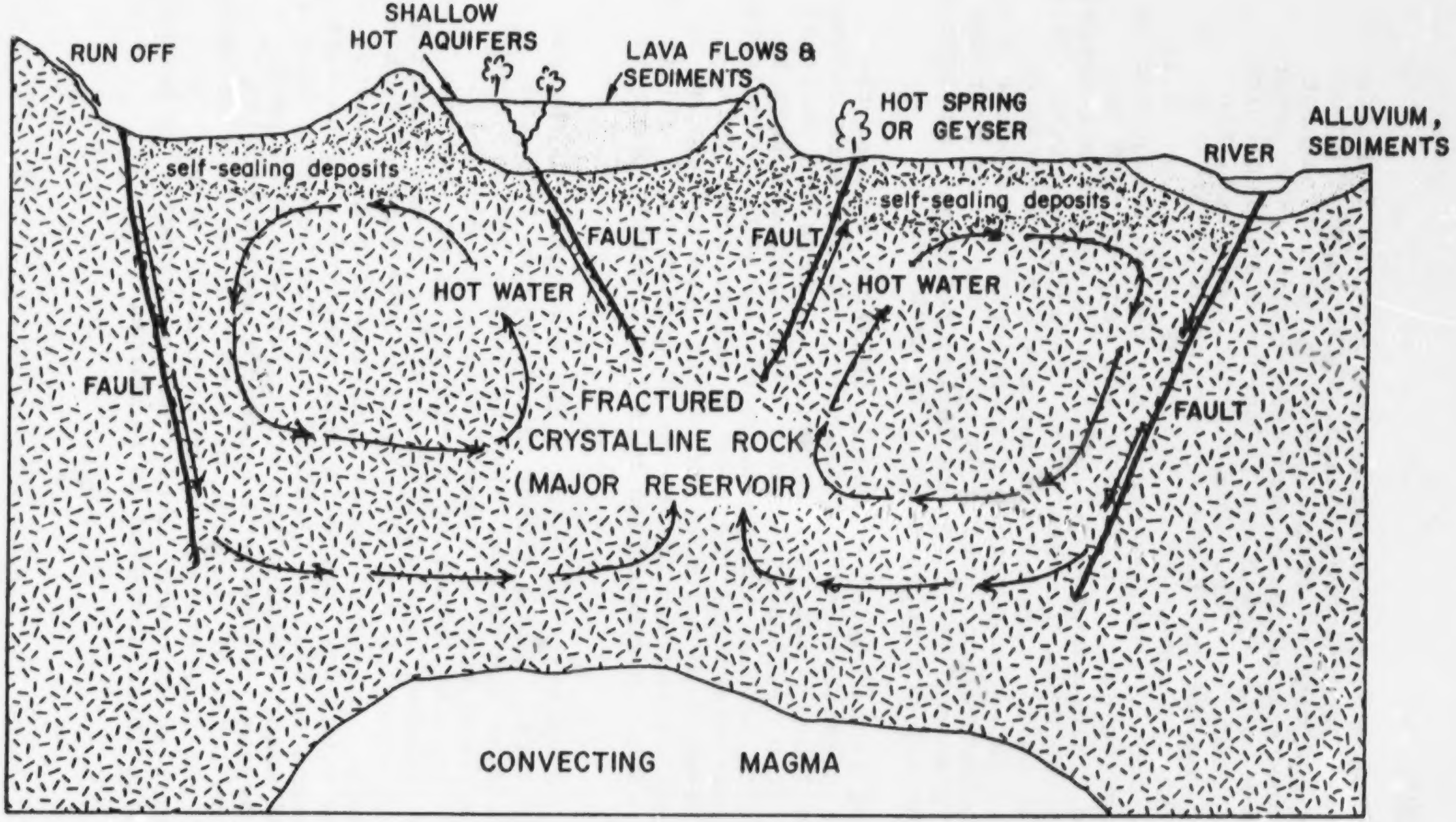

SHALLOW HOT AQUIFERS
RUN OFF
LAVA FLOWS & SEDIMENTS
HOT SPRING OR GEYSER
ALLUVIUM, SEDIMENTS
RIVER
self-sealing deposits
self-sealing deposits
FAULT
FAULT
FAULT
FAULT
HOT WATER
HOT WATER
FRACTURED CRYSTALLINE ROCK (MAJOR RESERVOIR)
CONVECTING MAGMA

Figure 2.1 Schematic diagram of a hydrothermal reservoir in an extinct volcanic caldera. (modified from Meidav and Sanyal, 1976)

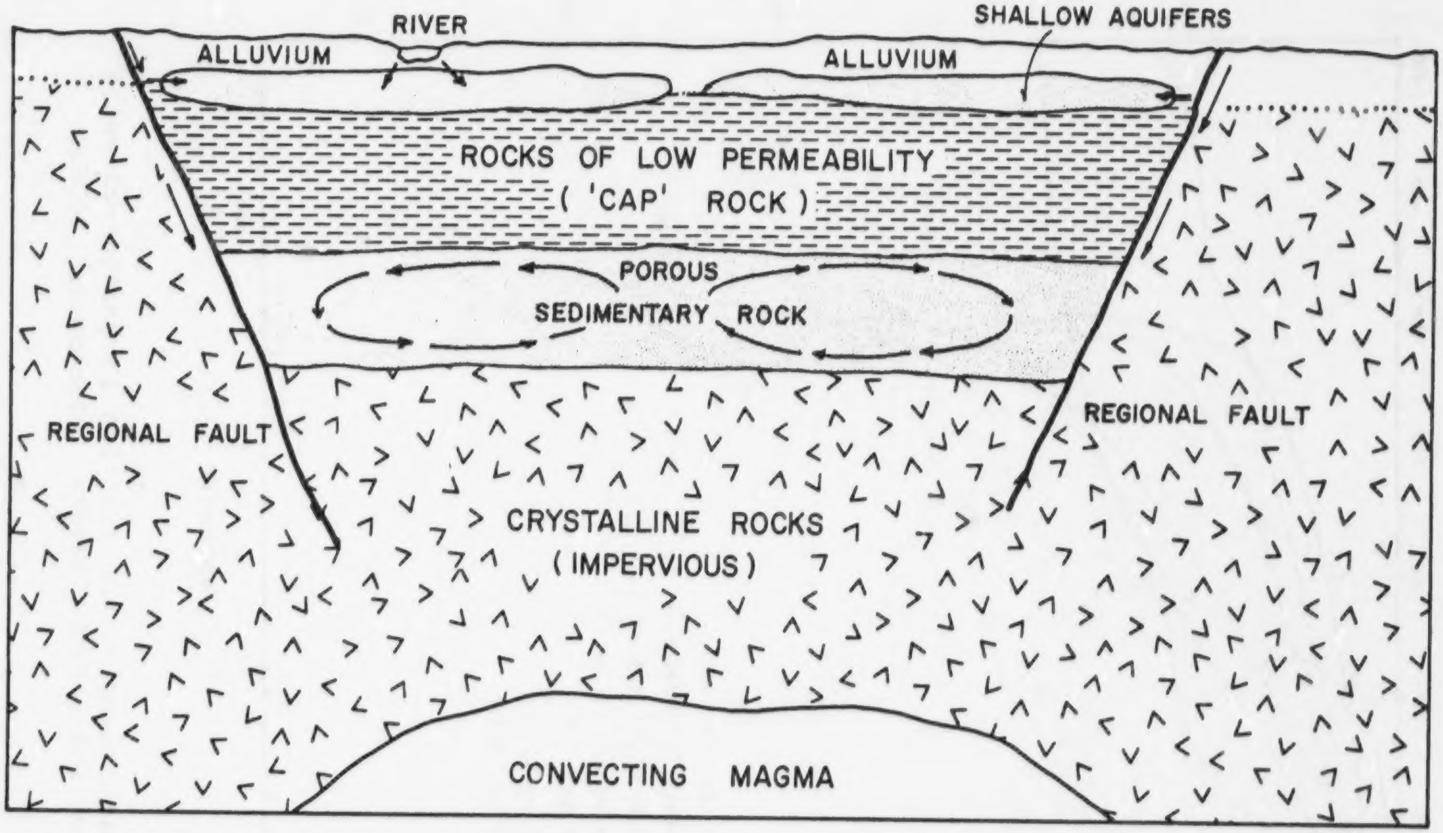

RIVER
SHALLOW AQUIFERS
ALLUVIUM
ALLUVIUM
ROCKS OF LOW PERMEABILITY
('CAP' ROCK)
POROUS
SEDIMENTARY ROCK
REGIONAL FAULT
REGIONAL FAULT
CRYSTALLINE ROCKS
(IMPERVIOUS)
CONVECTING MAGMA

Figure 2.2 Schematic diagram of a volcano-tectonic hydrothermal reservoir in a sedimentary basin. (Meidav and Sanyal, 1976)

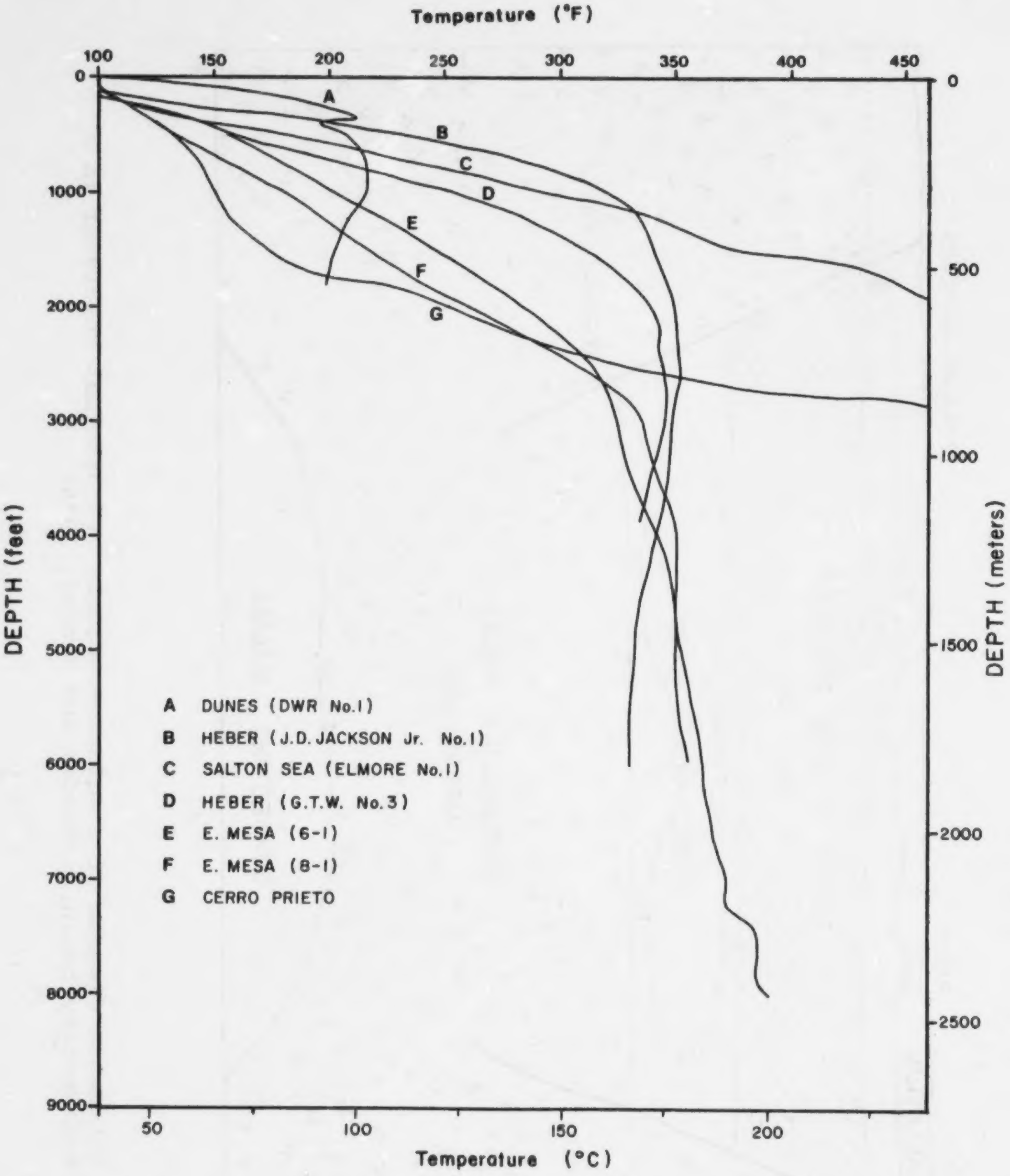


Figure 2.3 Static temperature profiles in geothermal wells from the Salton Trough. (Geonomics, 1978a)

2.3.2 Conceptual Models for Two Types of Geothermal Reservoirs

Two of the most common types of hydrothermal reservoirs are volcanic and volcano-tectonic (Figs. 2.1 and 2.2). Both types occur in areas of thinner than normal crust with shallow, recent volcanism nearby. In the entire area west of the Rocky Mountains, the thickness is less than the average of 40 to 50 km (25 to 30 mi); for example, it is 13 to 22 km (8 to 14 mi) thick in Imperial Valley, California.

In both types of reservoirs, heat is transferred by conduction from a hot igneous mass to an aquifer. Local faults often improve this mechanism by providing paths for more efficient heat transfer by fluid convection. These areas may be associated with large, extruded lava fields, volcanic calderas or intrusives. Examples of these are the lava fields of the northwestern United States and Valles Caldera, New Mexico; Yellowstone, Wyoming; and Long Valley, California. The regular elliptical shape of the Salton Sea geothermal anomaly has supported the hypothesis that the heat source here is an intrusive at shallow depth.

Exploitable geothermal reservoirs occur where the heat source is near the surface and/or where the faults provide adequate channels for flow of hydrothermal solutions. The temperature and pressure of the fluids drop as they ascend along faults, fractures or pore spaces. This results in precipitation of silica and other minerals, or hydrothermal alteration of the rock causing kaolinization, thereby sealing these channels in the rock mass. Local tectonic adjustments may provide movement necessary to keep some of these channels open. If they do not remain open, the self-sealing mechanism will migrate to an equilibrium depth where the temperature and pressure are sufficient to provide conditions for the minerals to remain in solution or not otherwise undergo alteration.

All high temperature hydrothermal reservoirs must have a caprock (Facca, 1973). This may be a primary feature, formed by deposition of an impermeable layer; for example, the deltaic clay in Imperial Valley, or, it may be a secondary feature formed by the self-sealing mechanism described above. An example is the sealing of the fracture permeability in the hard, fractured Franciscan graywacke in The Geysers steam field.

The difference between the volcanic and volcano-tectonic reservoirs lies in the subsurface structure, rock types and tectonic framework. Table 2.1 provides a convenient comparison of the distinctive attributes of the two conceptual hydrothermal reservoir models.

TABLE 2.1 COMPARISON OF TWO CONCEPTUAL HYDROTHERMAL RESERVOIR MODELS (modified from Meidav and Sanyal, 1976)

Attribute	Volcano-Tectonic (Sedimentary) Model	Volcanic Model
Surface manifestations	Limited	Some
Drilling cost	Relatively lower	Relatively higher
Formation evaluation and application of borehole logging	Simple	More complex
Porosity and permeability	Largely intergranular	Controlled by fractures
Vertical Permeability	Restricted due to interbedded impermeable layers	Similar to horizontal in places
Storage and flow capacities	Often distributed uniformly	Distributed non-uniformly
Reservoir development and performance prediction	Relatively simple	More difficult
Potential subsidence	Likely unless spent fluid is injected	Less significant

Volcanic Model--

In the volcanic system the reservoir consists of a fairly homogeneous faulted and fractured crystalline igneous or metamorphic fluid saturated mass (Fig. 2.1). It may occur underneath a volcanic caldera, with the collapse structure filled with lava flows and sediments. The Long Valley, California geothermal system is an example of this model.

A shallow magma chamber supplies heat to the reservoir by conduction. Large scale thermal convection cells, modified by faults and fractures, develop as the fluid in the fractures is heated. The convecting hydrothermal solutions circulate within the crystalline rock mass, depositing silica and/or carbonate near the top of the convection cell, thereby sealing the system. The reservoir is most likely bounded by faults, and may contain faults within its boundaries. The boundary faults may conduct meteoric, fluvial or lacustrine water to recharge the reservoir. The interior faults may conduct some of the hydrothermal solutions to the surface, thus producing surface geothermal manifestations. These may be warm or hot springs, geysers, steam, hydrothermal rock alterations, silica and travertine sinter, warm ground water temperatures, fumaroles and solfataras or hot soils. Shallow hot aquifers recharged by the underlying reservoir may also be present. However, the lack of surface manifestations does not preclude the existence of a subsurface geothermal reservoir, and surface manifestations do not imply the existence of an exploitable resource.

Volcano-Tectonic Model--

In the volcano-tectonic model (Fig. 2.2) sediments are deposited in a regional structural depression as it is progressively downdropped from surrounding areas. The reservoir consists of porous, clastic sediments with intergranular permeability. The porous layers may be interspersed with less permeable clay or volcanic flows. The geothermal fluid is confined between a low permeability caprock and an impermeable basement rock. Boundary faults or areas of lower permeability define the limits of the system.

In this system heat is conducted from the heat source through the crystalline rocks of the thin crust up to the sedimentary deposits containing ground water. This water is heated, rises and circulates back down forming a convection cell. Faults extending deep into the basement complex and closer to the heat source may also conduct some fluid up to the convection cell. The convecting current is limited in its upward extent by the reservoir caprock of either an existing impermeable layer such as a shale, or one produced by the self-sealing mechanism of the convecting fluids. It is probably limited in its lateral extent by structural features.

More permeable sediments may overlie the caprock and contain the shallow aquifers of a distinct ground water flow system. Recharge to the geothermal system may be conducted by bounding faults or by downward percolation from the overlying aquifers. This may occur through parts of the low permeability caprock some distance from the convection cell. Surface manifestations are generally less common in this type of system.

The geothermal systems in Imperial Valley are examples of such a model. It is a broad structural and topographic depression that has been filled with over 6,200 m (20,000 ft) of later Tertiary deltaic and lacustrine sands, silts and gravels overlain by alluvium and lake sediments (Biehler, 1964). The underlying pre-Tertiary granitic and metamorphic complex is intensely step-faulted down from the mountains on both sides of the valley. A specific model for the Salton Sea geothermal field is described below.

2.3.3 Salton Sea Geothermal Field Model

A ground water and geothermal system model for the Salton Sea geothermal field in Imperial Valley must consider: the fault systems in the valley, the great variation in salt concentration in geothermal brines, two different meteoric water sources, up to 6,000 m (20,000 ft) of sands, silts and clays overlying an igneous and metamorphic basement complex and an apparently random distribution of geothermal anomalies in the valley (Rex, 1970). Conceptual models for genesis of Salton Sea geothermal fluids have been proposed by Craig (1966), Berry (1966), Helgeson (1968), White (1968) and Dutcher, et al. (1972). The last of these is described below.

In this model (Fig. 2.4), a shale dominant layer overlies a sandstone dominant fractured brine reservoir. The interface between these two layers in Imperial Valley appears to be generally between 600 and 900 m (2,000 and 3,000 ft); although it might be only about 300 m (1,000 ft) at Heber (Meidav, et al. 1975). Recharge is through downward percolation from shallower aquifers above the brine reservoir and near the basin margins. Part of the driving force for this water is the higher hydrostatic pressure of the cooler water outside the convection cells (Dutcher, et al., 1972, p. 30-32). This inflowing water has low oxygen and deuterium isotope ratios, which imply that the water has not yet been heated. The model suggests high calcium sulfate and a TDS content of about 35,000 mg/l for the recharge water of the Salton Sea geothermal field. The downward percolating water is heated and its temperature increases as it flows towards the convection cell.

The convecting brine becomes concentrated by escape of water, carbon dioxide, hydrogen sulfide and other vapors through

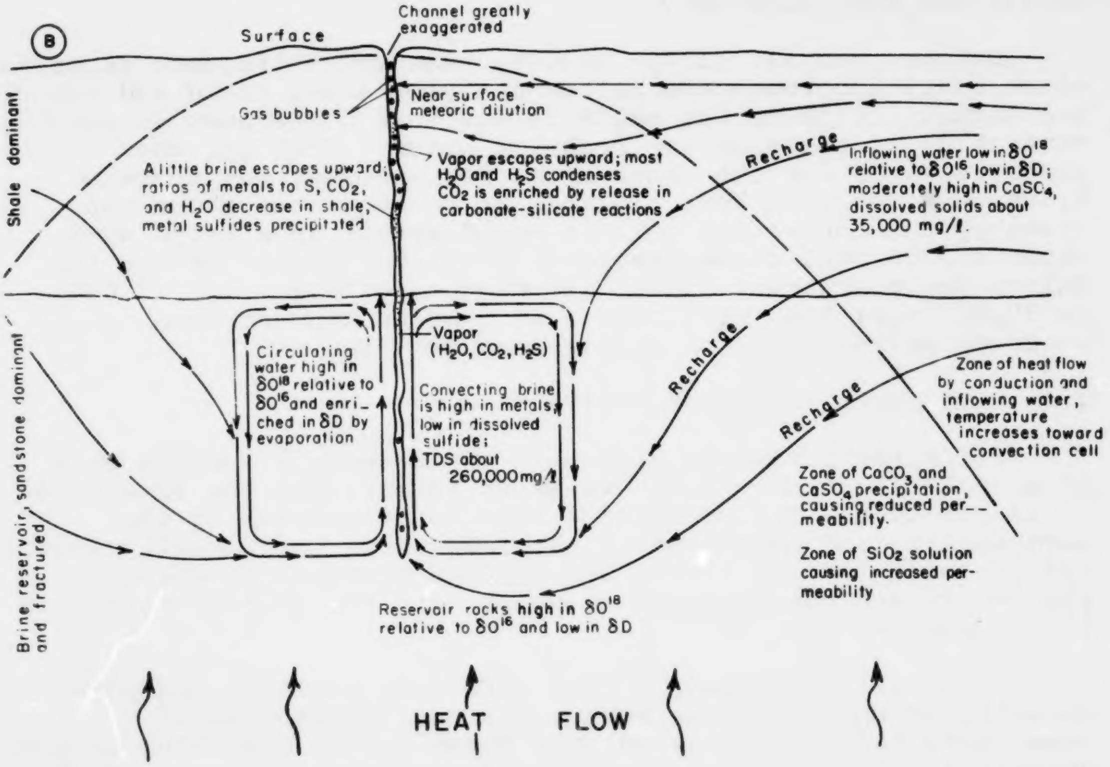

B
Surface
Channel greatly exaggerated
Gas bubbles
Near surface meteoric dilution
Shale dominant
A little brine escapes upward; ratios of metals to S, CO2, and H2O decrease in shale, metal sulfides precipitated
Vapor escapes upward; most H2O and H2S condenses CO2 is enriched by release in carbonate-silicate reactions
Recharge
Inflowing water low in δO18 relative to δO16, low in δD; moderately high in CaSO4, dissolved solids about 35,000 mg/l.
Brine reservoir, sandstone dominant and fractured
Circulating water high in δO18 relative to δO16 and enriched in δD by evaporation
Vapor (H2O, CO2, H2S)
Convecting brine is high in metals, low in dissolved sulfide; TDS about 260,000 mg/l
Recharge
Recharge
Zone of heat flow by conduction and inflowing water, temperature increases toward convection cell
Zone of CaCO3 and CaSO4 precipitation, causing reduced permeability.
Zone of SiO2 solution causing increased permeability
Reservoir rocks high in δO18 relative to δO16 and low in δD
HEAT FLOW

Figure 2.4 Modified model for Salton Sea geothermal system showing source of recharge and water quality changes. (Dutcher, et al. 1972)

fractures in the reservoir. Most of the water and hydrogen sulfide condenses in the upward escaping vapor. Carbon dioxide is enriched by release in carbonate-silicate reactions with the surrounding rock. The convecting brine becomes high in metals, low in dissolved sulfide and may attain a maximum TDS content up to 385,000 mg/l. Within and around the convection cell, hydrothermal fluids are precipitating calcium carbonate and calcium sulfate, which reduces permeability in the reservoir; while the same fluid is dissolving silica causing increased permeability. Brine that escapes upward reacts with the shale, resulting in lower ratios of metals to sulfur, carbon dioxide and water. Metal sulfides are also precipitated. It is a dynamic system and all these processes and chemical reactions occur continuously and simultaneously.

Dutcher, et al. (1972) suggest that the difference in brine concentration between the Salton Sea geothermal field and other geothermal fields to the south is due to a difference in concentration of salts in the recharge water. That is, the recharge water for the Heber area, for example, may contain 1,500 to 2,000 mg/l TDS. If this is concentrated about ten times by the convection cell it would result in a brine with about 20,000 mg/l concentration. A similar mechanism for the Salton Sea geothermal field, assuming a recharge with 25,000 to 35,000 mg/l TDS, will result in a brine concentrated to hundreds of thousands of milligrams per liter TDS.

2.4 GEOTHERMAL RESERVOIR ENGINEERING

For effective waste disposal, the reservoir must be able to accept all of the liquid waste at essentially the same rate it is produced. The production rate is determined by the permeability and thickness of the reservoir, the specific weight and viscosity of the fluid, the applied pressure gradient, the number and construction of wells, and the overall reservoir flow dynamics.

Permeability depends on the effective porosity and pore geometry of the reservoir rock. Porosity in geothermal reservoirs can be classified into three groups according to pore geometry: (1) fracture porosity; (2) sedimentary intergranular porosity; and (3) vesicular or vuggy porosity. Fracture porosity can be superimposed on intergranular, vesicular or vuggy porosity, creating more complex flow regimes. In geothermal reservoirs, fracture porosity is by far the most common, followed by intergranular; vesicular and vuggy porosities are rare. Most reservoirs in igneous rocks have only fracture porosity. High permeability and relatively low porosity are typical of fracture porosity. The producing zones at The Geysers, for example, have permeabilities up to several darcies, but porosities are on the order of only 2 to 5%. On the other hand, sedimentary reservoirs with intergranular pore geometry usually have moderate to low permeability and high porosity. Permeabilities of 200 millidarcies with 20% porosities, are typical for the sedimentary reservoirs in the Imperial Valley. Fracture porosity may also be superimposed on intergranular, vesicular or vuggy porosity thereby creating more complex flow regimes.

Volcanic flows, especially basalts, sometimes have vesicular pore geometry. In this type, permeability is not directly related to porosity. A highly porous pumice may have very low permeability due to the lack of interconnection between the voids. Vuggy porosity, a term generally applied to reservoirs in carbonate rock, also gives rise to highly variable permeability, depending upon the continuity of the vugs (solution voids).

The variation of hydraulic conductivity with temperature around production and injection wells in a geothermal reservoir must be considered. Hydraulic conductivity, K, is a function of permeability, k, specific gravity of the fluid, g, and viscosity of the fluid, v, (see Section 1.4 on terminology), according to the following equation:

$$K = \frac{kg}{v}$$

The high temperatures of geothermal systems cause fluid viscosity to fall more rapidly than the specific gravity thereby increasing hydraulic conductivity up to several hundred percent compared to that for normal ground water temperatures.

The extraction and injection of fluids for geothermal energy production will change the natural flow regime. Location and depth of producing and injection wells, as well as the rate of withdrawal and injection, will greatly affect the flow dynamics, and consequently the productivity of the reservoir. Mathematical modeling of various combinations of injection and production rates, locations, and depths superimposed on the natural reservoir dynamics will aid in optimizing energy production.

In addition to the fluid flow regime, it is important to define the heat transfer mechanisms in a geothermal reservoir before designing the energy production-injection system. The long-term effects of injecting relatively cool liquid waste into a geothermal reservoir must be evaluated. These effects depend on the permeability, density, thickness and heat capacity of the reservoir rock, regional fluid flow rate, spacing of injection and production wells, rates of production and injection and the temperature of the injected fluid. A conceptual basis for understanding these interactions can be provided by the hypothetical reservoir models described below.

2.4.1 Hypothetical Reservoir Models

Several hypothetical reservoir models are discussed in this subsection so the reader may develop a sense of the flow dynamics in a producing reservoir. The models presented show streamlines and the advance of cold fronts from the injection wells in three types of production-injection patterns.

The reservoir and fluid properties for the first hypothetical reservoir are presented in Table 2.2 and their derivation is summarized below.

Data for typical values of depth, area, gross thickness and temperature were synthesized from Renner, et al. (1975). The porosity, permeability, salinity and net thickness values were assumed to be reasonable average estimates. The density and viscosity were taken from standard tables for the specified temperature, pressure and salinity of the fluid. Depth versus pressure data for several reservoirs were used to derive the hydrostatic gradient. The remaining parameters were computed from these assumptions.

A downhole pumping exploitation scheme for the reservoir is generated using the data in Table 2.2 and representative flow rate of 0.063 cu m/sec (1000 gpm) per well. Four assumptions will help define the exploitation scheme:

1) The reservoir is cylindrical.

2) The hottest part is at depth in the center.

3) The temperature declines towards the edges.

4) All produced fluid will be injected.

Hence, the production wells will be placed in the center of the reservoir to exploit the hottest fluid. The cylindrical shape suggests that the injection wells be placed in a circular array in the peripheral cooler part of the reservoir. Fig. 2.5A illustrates a pattern such as this with a symmetrical well arrangement where the injection rate per well is double the production rate; therefore, there are twice as many producing wells as injection wells. Fig. 2.5B illustrates an idealized flow (stream line) pattern for a hypothetical production scheme with eight production and eight injection wells. The production rate is the same as the injection rate for each well.

TABLE 2.2 PROPERTIES OF THE HYPOTHETICAL RESERVOIR
(Meidav and Sanyal, 1976)

Depth	1800 m	(6000 ft)
Subsurface area	26 sq km	(10 sq mi)
Gross thickness	1200 m	(4000 ft)
Net thickness (permeable zone)	300 m	(1000 ft)
Bulk volume	31.7 cu km	(7.6 cu mi)
Reservoir temperature (highest near the center, cooler near the edges)	138°-163°C	(280°-325°F)
Gross stored heat	1.09×10^{19} J	(2.6×10^{18} cal)
Gross electrical potential	3440 MW•centuries	
Net electrical potential	69 MW•centuries	
Expected life of a 200 MWe plant	35 years	
Porosity	15%	
Permeability	100 millidarcies	
Brine salinity (TDS)	5000 ppm	
Brine density	0.93 gm/cu cm	(58 lbs/cu ft)
Brine viscosity	0.2 centipoise	
Hydrostatic gradient	0.0009 MPa/m	(0.43 psi/ft)
Reservoir pressure	18.0 MPa	(2600 psia)
Maximum flow rate per unit pressure drawdown (Maximum productivity index)	144 kg/sec/MPa	(7980 lbs/hr/psi) (17.4 gal/min/psi) (588 barrels/day/psi) (93.5 cu m/day/psi)

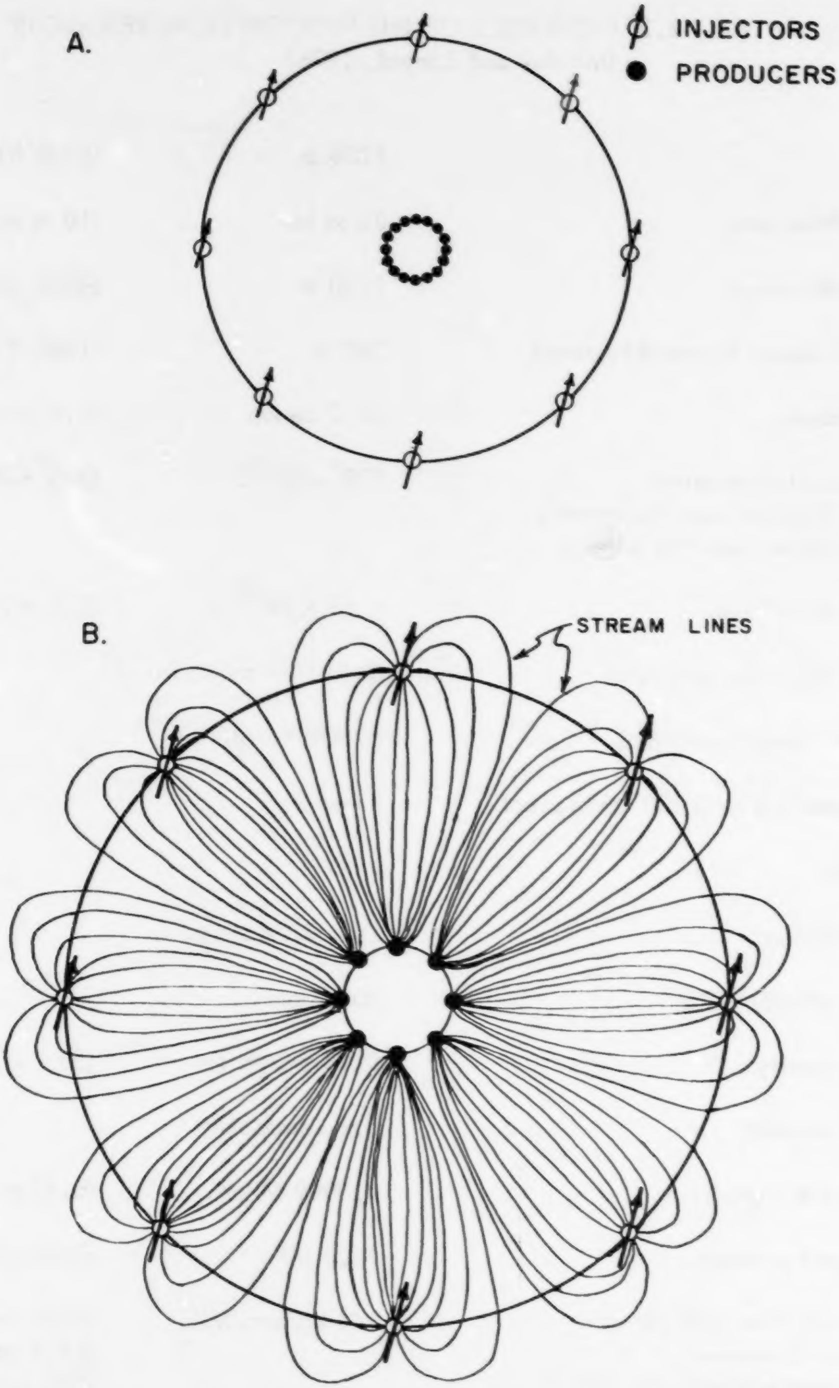

A.
INJECTORS
PRODUCERS
B.
STREAM LINES

Figure 2.5 Location of producing and injecting wells of a hypothetical reservoir. (Meidav and Sanyal, 1976)

Table 2.3 gives the downhole pumping exploitation characteristics of the hypothetical reservoir for a 50 MWe power plant. In this development a production rate of 0.063 cu m/sec (1000 gpm) will result in a calculated pressure drawdown of .39 MPa (57 psi). The actual drawdown, however, will be greater due to interference from nearby wells and poor completion efficiency. The cones of depression of adjacent producing wells will interfere with each other. The closer the wells, the greater the interference and the greater the drawdown in each well. Unavoidable limitations, such as the effect of well casing perforations, formation damage and incomplete penetration, all contribute to reduced well performance efficiency and thereby greater drawdown than those calculated for ideal conditions. Further details on these reservoir engineering aspects are provided in Meidav and Sanyal (1976).

Some other examples of hypothetical reservoir production and injection schemes are presented by Tsang, et al. (1977). A semi-analytic method was used to compute the progression of the stream lines and cold fronts. Two examples are shown on Fig. 2.6: one is a production-injection pair (doublet) and the other is a scheme with nine production and five injection wells. The flow lines, assumptions and specifications for each example are shown on the figure. In the production-injection doublet (Fig. 2.6A), the heating of the fluid in the rock matrix causes the cold front to progress more slowly than the hydrodynamic front from the injection well towards the production well. In this case it will take 15 years for the first cold front to reach the production well. Up to that time the production temperature will not be affected by the injection. Then the temperature will drop sharply, approaching the injection temperature asymptotically.

In the 14 well scheme (Fig. 2.6B) it will take 106 years for the first cold front to reach a production well. Several of the wells have much longer breakthrough times due to the interference of adjacent wells.

In modeling geopressured reservoirs, Pritchett, et al. (1977) determined that with injection a long interval of constant temperature reigns in the production wells. When the cold front from the injection wells reaches the production wells, the production temperature declines. In this model the production-injection well array is symmetrically arranged in a rectangular grid, with basically an equal number of production and injection wells.

TABLE 2.3 DOWNHOLE PUMPING EXPLOITATION CHARACTERISTICS OF A HYPOTHETICAL RESERVOIR FOR A 50 MWe POWER PLANT (modified from Meidav and Sanyal, 1976)

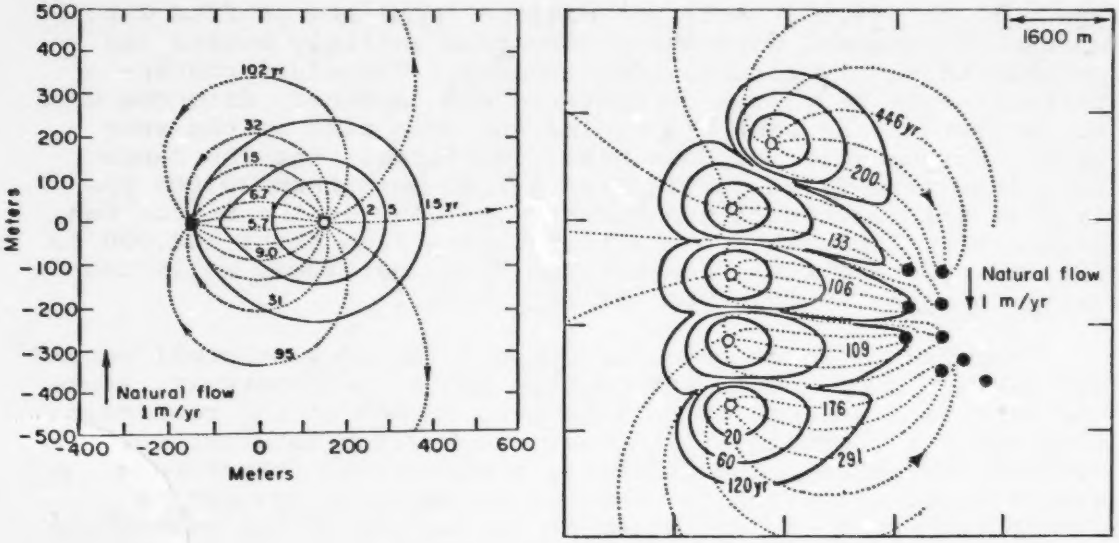
Parameter	Value	
Well Diameter (7-5/8 in OD casing)	17.5 cm	(6.875 in ID)
Well Drainage Radius	150 m	(500 ft)
Expected flow rate per well	0.063 cu m/sec	(1000 gpm)
Number of production wells	36	
Number of injection wells	18	
Injection rate per well	0.126 cu m/sec	(2000 gpm)
Flowing bottomhole pressure at producing well	11.6 MPa	(1680 psia)
Flowing bottomhole pressure at injection well	19.9 MPa	(2890 psia)
Flowing production wellhead pressure	0.52-0.69 MPa	(75-100 psia)
Shut-in production wellhead pressure	0.34 MPa	(50 psia)
Production wellhead temperature (average over 30 years)	150°C	(300°F)
Injection wellhead temperature	66°C	(150°F)
Injection wellhead pressure	0.69-1.38 MPa	(100-200 psia)

A. SPECIFICATIONS:

Distance between wells = 300 m.
Thickness of Aquifer = 100 m.
Porosity = 10%
Flow rate in each well = 100 m^3/hr

B. SPECIFICATIONS

Thickness of Aquifer = 300 m.
Porosity = 20 %
Flow rate in each well = 193 m^3/hr


500
400
300
200
100
0
-100
-200
-300
-400
-500
Meters
-400
-200
0
200
400
600
Meters
102 yr
32
15
6.7
5.7
9.0
2
5
15 yr
31
95
Natural flow
1 m/yr
1600 m
446 yr
200
133
106
109
176
291
20
60
120 yr
Natural flow
1 m/yr

EXPLANATION

······	Streamlines
——	Cold temperature fronts
31	Number of years for front to get to this location
○	Injection Well
●	Production Well

ASSUMPTIONS (Both Cases)

0.5 cal/cm^3/°C = Volumetric Heat Capacity of Rock

0.006 cal/cm/sec/°C = Thermal Conductivity of Rock

Figure 2.6 A. A production-injection doublet
B. A system of nine production and five injection wells
(Tsang, et al. 1977)

2.5 THE CHARACTER OF THE GEOTHERMAL EFFLUENT

2.5.1 Chemistry

The chemical characteristics of geothermal fluids throughout the world vary over a wide range, both in number of chemical species and their concentrations. For example, TDS ranges from about 50 to 388,000 parts per million (ppm) and pH from 2 to 10 units. Geothermal waters can vary from entirely benign and potable to highly corrosive and saline. The fluid characteristics may vary from one reservoir to another, from one well to another in the same reservoir, and over time in the same well. For example, at East Mesa, California, the TDS ranges from less than 2,000 ppm in Mesa 5-1 to more than 30,000 ppm in Mesa 6-1 (Littleton and Burnett, 1978). In the Salton Sea, California, field the composition varies from about 100,000 to 387,500 ppm, and fluid composition from individual wells can vary more than 100,000 ppm (Palmer, 1975).

Knowledge of the chemical composition of geothermal waters can provide much useful information about the reservoir, since the kinds and amounts of constituents depend on the reservoir environment: formation lithology, rock-water interaction, rock-mineral-chemical equilibria, pressure and temperature. A geographical variation in chemical characteristics can be attributed mainly to variation in the nature of the subsurface rocks, temperature, and distance from the source of recharge. Temporal variation in the chemistry of geothermal fluids at a particular site can have a number of causes, the most important being the variation in the rate of fluid recharge (natural or artificial) into the reservoir.

Although it is difficult to make a meaningful comparison of geothermal fluid chemistry from various parts of the world, some general correlations can be made. Low TDS is usually associated with relatively low concentrations of each constituent. Hotter waters tend to contain higher concentrations of constituents. More saline waters appear to have a lower pH.

Because of the chemical diversity in geothermal waters, it is difficult to arrive at an average value for concentration of each constituent. As more data become available, statistically significant mean and median values of each constituent may be determined, at least for certain geographical areas. The median value of TDS for geothermal water will most likely be in the 5,000 to 10,000 ppm range. Most geothermal fluids appear to be acidic; that is, with pH less than 7.

In addition to dissolved and suspended solids, geothermal water and steam contain a variety of noncondensible gases, some of which may be detrimental to the surface environment. Hydrogen sulfide, a noncondensible gas constituent of many geothermal fluids, has drawn considerable attention at The Geysers, California, because of its odor. The other major noxious components of many geothermal vapors are ammonia, carbon monoxide, sulfur dioxide and mercury. Usually, noncondensible gases constitute between 0.3% and 5% of the volume of the flashed steam from geothermal fluids (Wood, 1973).

Small amounts of various toxic constituents are often present in geothermal fluids. These include arsenic, boron, nickel, zinc, rubidium, strontium and barium.

Geothermal fluids usually contain certain radioactive elements in low concentrations, mainly radon, radium and isotopes of uranium and thorium. The most thoroughly studied radioactive element in geothermal fluids is radon^{222}, a radioactive gas. A study of 136 natural geothermal springs showed a range of 13 to 14,000 picocuries per liter (pCi/l), with a median around 510 pCi/l (O'Connell and Kaufman, 1976).

Effluent from most vapor-dominated systems contains significant amounts of hydrogen sulfide, which has an offensive odor and is highly toxic. Ammonia, carbon dioxide, methane and boric acid are also present in steam at The Geysers, but have not posed a problem. Mercury vapor is common in vapor-dominated systems and could pose a health hazard if allowed to accumulate in the environment. Radium in geothermal vapor may precipitate from solution and the radioactivity could be hazardous if radium accumulates in the scale in transmission pipes. Radon is found in the noncondensible gas fraction of some geothermal steam, but unless trapped by a long period of atmospheric inversion it would not be a health or safety hazard. The boron content in the liquid fraction of The Geysers system has made injection of liquid waste imperative there.

Liquid-dominated systems have essentially the same vapor chemistry as the vapor-dominated systems. The liquid fraction generally has high concentrations of salt and trace metals, and a variety of other contaminants. Corrosion and surface and ground water contamination can be serious problems in developing liquid-dominated systems.

Small releases of radioactive elements may result from rock fracturing. However, these will probably not exceed nuclear power industry standards. Air and water quality problems in development of hot dry rock systems are not expected to be as severe as in convection systems, since introduced fluids are circulated through the hot dry rock in a closed cycle. Scaling and clogging could occur if the fluids become saturated with minerals in the fractured rock chamber.

Fluids in geopressured systems have high methane concentrations. The geothermal liquid probably is highly saline and corrosive.

Because electricity generation requires hotter waters, the geothermal effluent is often more saline and generally poorer than that from nonelectric uses.

Chemicals, such as acids or bases used for pH adjustment, may be added to geothermal fluids to minimize scaling and corrosion or to remove certain constituents. Although these chemicals are not expected to be highly detrimental in themselves, they may contribute to degradation of the geothermal liquid.

Chemical Characteristics and Water Use--

Chemical composition data for geothermal fluids is summarized and compared with the chemical composition of drinking water, selected regulatory standards and sea water in Table 2.4 and Fig. 2.7.

Geothermal waters may contain a high concentration of trace elements compared to meteoric and sea water. Geothermal waters in most instances cannot be used as a domestic or irrigation water resource, due to high salinity and high concentrations of trace elements, especially arsenic, boron, barium, fluoride, manganese and zinc. These waters also contain significant quantities of lithium, an element so unusual in ordinary water that it is used as a tracer in ground water studies.

Because the trace element concentrations in water from various geothermal fields and even from individual geothermal wells in the same field differ substantially, hazards due to trace element concentrations in geothermal fluids must be individually evaluated.

A good background discussion of water quality with respect to potential use appears in the section titled "Relationship of Quality of Water to Use" in Hem (1970) and in Appendix A, "Identification Systems and Criteria Used in this Report" in California Department of Water Resources (1970).

2.5.2 Temperature

The temperature of spent geothermal effluent depends upon its original temperature and the type and efficiency of power plants range from about 45 to 120°C (110 to 250°F).

Waste heat can be significant in electric power generation. As much as 85% of the available heat is wasted because of the

TABLE 2.4 COMPARISON OF INORGANIC CHEMICAL WATER STANDARDS WITH GEOTHERMAL AND SEA WATER ANALYSES (Geonomics, 1978b)

Substance	Drinking Water^{a} (mg/l) USPHS Recommended	Drinking Water^{a} (mg/l) USPHS Mandatory	Irrigating Water^{b} (ppm) Threshold	Irrigating Water^{b} (ppm) Limiting	Livestock Feeding Water^{b} (ppm) Threshold	Livestock Feeding Water^{b} (ppm) Limiting	Geothermal Water^{c} (ppm) Range	Sea Water^{d} mg/l
Arsenic	0.01	0.05^{g}	1.0	5.0	1	-	0- 12	0.003
Barium	-	1.0^{g}	-	-	-	-	0- 250	0.03
Bicarbonate	-	-	-	-	500	500	0- 10,000	142
Boron	-	-	0.5	2	-	-	0- 1,200	4.6
Cadmium	-	0.01^{g}	-	-	5	-	0- 1	trace^{f}
Calcium		-	-	-	500	1,000	0- 63,000	400
Chloride	250^{h}	-	100	350	1,500	3,000	0- 240,000	19,000
Chromium	-	0.05^{g}	-	-	-	-	-	-
Copper	1.0^{h}	-	0.1	1.0	-	-	0- 10	0.003
Fluoride	1.7	2.2	-	-	1	6	0- 35	1.3
Hydrogen Sulfide	-	0.05^{h}	-	-	-	-	0.2- 74	-
Iron	0.3^{h}	-	-	-	-	-	0- 4,200	0.01
Lead	-	0.05^{g}	-	-	-	-	0- 200	trace^{f}
Magnesium	-	-	-	-	250	500	0- 39,000	1,350
Manganese	0.05^{h}	-	-	-	-	-	0- 2,000	0.002
Mercury	-	0.002^{h}	-	-	-	-	0- 10	trace^{f}
Nitrate	45	10^{g}	-	-	200	400	0- 35	0.5^{e}
Selenium	-	0.01^{g}	-	-	-	-	trace^{f}	0.004
Silver	-	0.05^{g}	-	-	-	-	0- 2	trace^{f}
Sodium		-	-	-	1,000	2,000	0- 80,000	10,500
Sulfate	250^{h}	-	200	1,000	500	1,000	0- 84,000	2,700
Zinc	5^{h}	-	-	-	-	-	0- 970	0.01
TDS	500^{h}	-	500	1,500	2,500	5,000	47- 390,000	34,560
pH	-	6.5-8.5^{h}	7.0-8.5	6.0-9.0	6.0-8.5	5.6-9.0	2- 10	-

[a] USPHS, 1962; EPA, 1976; EPA, 1977a

[b] Todd, 1970

[c] Tsai, et. al., in press

[d] Goldberg, 1963

[e] Includes NO_2^-, NH_4^+ and dissolved nitrogen gas

[f] Trace = <0.001 ppm (or mg/l)

[g] Maximum contaminant level specified in National Interim Primary Drinking Water Regulations (EPA, 1976)

[h] Maximum contaminant level specified in National Secondary Drinking Water Regulations (EPA, 1977a)

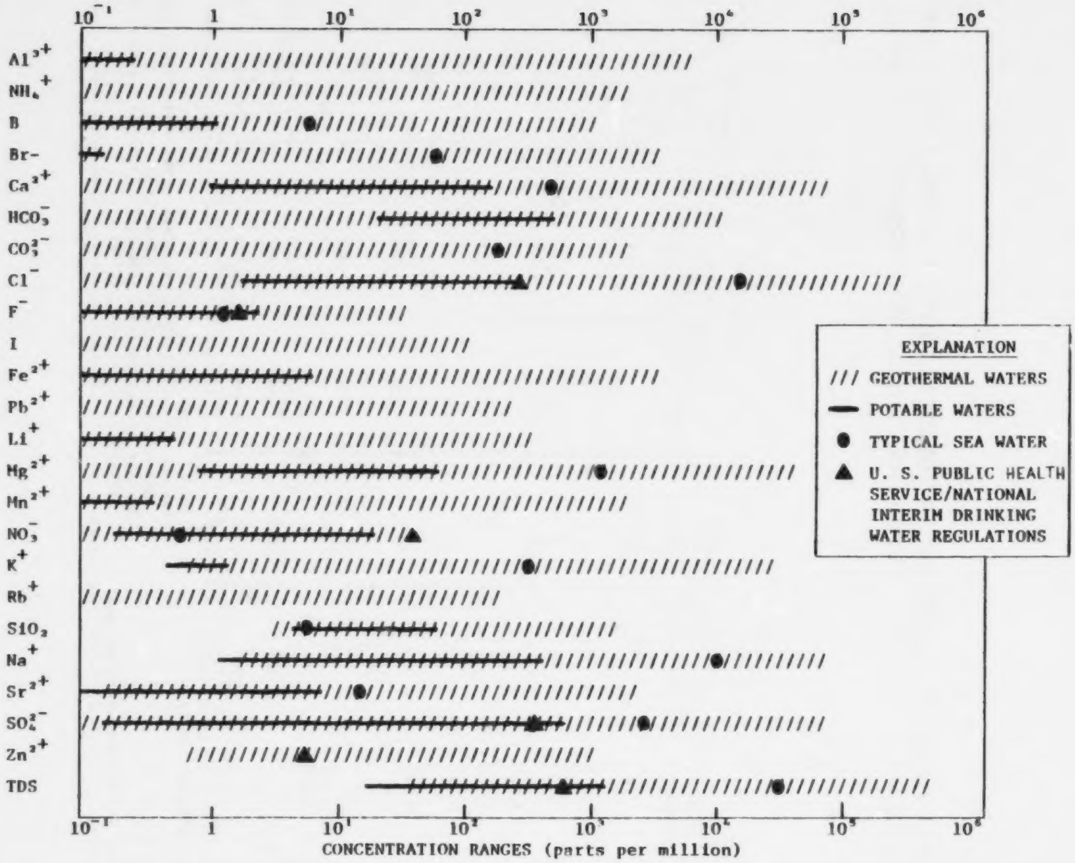


Figure 2.7 Comparison of concentration ranges of constituents in geothermal and potable waters. (modified from Tsai, et al. 1978)

inefficiency of low-temperature conversion. Depending on the cooling method, this heat is dissipated to the air (as with cooling towers), discharged to surface water (from once-through cooling water), or disposed of with the geothermal fluid.

In a total flow system, such as that proposed by Lawrence Livermore Laboratory for the hot corrosive brines of the Imperial Valley, most of the thermal energy--both liquid and vapor--is used for power production; the temperature of the spent fluid is low. In contrast, a one-cycle flashed steam system uses only the steam fraction to drive the turbine. The remaining unflashed water, comprising approximately 2/3 of the total mass of produced fluid is discarded at high temperatures. For example, it is estimated that a fluid from a 223°C (434°F) well will be discharged from the conversion facility at 167°C (338°F).

2.5.3 Volume of Fluid

Several factors affect the volume of spent fluid discharged from a geothermal conversion facility. These factors include: type of system, use of the energy, capacity of the facility, design of the conversion system and type of cooling method.

Liquid waste from hot dry rock systems may be minimal. Water used for recovery is generally recycled through the hot reservoir.

Much more fluid by weight is produced by liquid-dominated fields than by vapor-dominated fields. The Wairakei field, for example, produces 11.3 cu m/sec (180,000 gpm) of combined wastewater, steam and condenser effluent. This is approximately 200 times the fluid volume produced by The Geysers per unit of electricity (Swanberg, 1976).

Plants developed for direct use of geothermal energy are generally of a smaller scale than electric power facilities and do not generate as much spent fluid. Such uses are space heating, industrial process heating and agricultural applications such as aquaculture, greenhouse heating and lumber processing.

2.6 RESOURCE RECOVERY

Resource recovery refers to the extraction of heat from the geothermal reservoir. Four aspects of injection related to resource recovery are: (1) maintenance of reservoir pressure; (2) replenishing the geothermal fluid supply; (3) recovering the latent heat content of the reservoir rocks; and (4) possible cooling of the geothermal reservoir fluid.

In most geothermal systems the duration of sustained fluid production or recharge mechanisms is not well defined. Properly emplaced artificial recharge, by injection, may alleviate these concerns. Natural recharge of the reservoir may not be sufficient for the sustained flow rates necessary for electric power production. Recharge by injection may make up the difference between the natural recharge and the fluid production necessary for power production.

If the voidage created in the reservoir by fluid extraction is not filled the hydrostatic pressure will decline. Declining pressure will cause declining productivity at the wellhead. If the pressure is allowed to drop sufficiently then steam will form in the reservoir. While steam does extract heat from the rock matrix, it is not as efficient as water as a heat transfer medium (Nathenson and Muffler, 1975). Additionally, steam from a low-pressure reservoir may not provide the temperature and pressure necessary at the wellhead for electric power generation.

In addition to providing fluid for a discharge-recharge balance, the injected fluid may provide additional recoverable heat. The total heat content of a geothermal system consists of heat in the rock matrix plus heat in the water. Generally, the water contains a much smaller proportion of heat than the rock matrix. Cooler fluid injected into the reservoir will provide a medium for transfer of more of the heat energy contained in the rock. Injection wells must be far enough from production wells so that the fluid residence time is long enough to sufficiently reheat the fluid. If fluid is injected too close to the production wells, or in an otherwise inappropriate location, it may cool the existing heated fluid and reduce power production. Hence, proper location of injection wells is critical.

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SECTION 3

THE MONITORING METHODOLOGY

The uniqueness of the natural environment and human activities in each potential development area prevents specification of one "monitoring plan" (see Section 1.4 on terminology) that would apply to all sites. The ground water "monitoring methodology" for geothermal development described below provides a set of guidelines to aid in designing a site-specific monitoring plan.

The methodology is a synthesis of approaches described in several publications, governmental regulations and policies as well as the personal experience of the authors and consultants. It provides a systematic and comprehensive step-by-step outline to develop a site-specific ground water monitoring plan for geothermal development. However, it is by no means a cookbook, and each step requires evaluation and analysis for each site. It is important that personnel applying this methodology have a thorough knowledge of geology, hydrology and geochemistry.

The six steps of the methodology (Fig. 1.2) are:

1) Define geologic, hydrologic and geochemical baseline conditions as well as projected reservoir and plant development;

2) Forecast aquifer conditions in the geothermal reservoir as well as in overlying aquifers;

3) Define temporal, spatial and chemical limits of detection;

4) Evaluate monitoring techniques for both injection and observation wells;

5) Design monitoring plan and alternatives;

6) Implement monitoring plan.

The methodology is applicable to release of geothermal fluid on the ground surface as well as below the surface. The discussions emphasize monitoring, the major continuing ground water degradation threat of fluid injection. An accidental spill, blowout or other mishap may release geothermal fluid on the ground surface. However, this is a temporary, unpredictable and often a practically unavoidable situation not subject to the detection problems of a subsurface release. Whenever such an incident occurs, the problem is likely to be detected and treated immediately. Unless preventive measures are taken (see Section 3.1.5) the fluid may percolate into a near-surface aquifer or discharge into surface water.

For a surface release, the study of baseline conditions, as specified in the methodology, will allow estimation of the rate and direction of percolation and the chemical reactions of an effluent with the near-surface sediments. A monitoring program could also be set up, along the guidelines outlined in the methodology, to detect the actual progress of the near-surface degraded fluid front. This type of potential degradation due to percolation from the surface is treated in more detail in Todd, et al. (1976).

The steps in the methodology would generally be applied in the order shown in Fig. 1.2 and are discussed below.

3.1 DEFINE BASELINE CONDITIONS AND PROJECTED DEVELOPMENT

Baseline conditions are those that exist prior to development. These conditions may be natural or already altered by human activities. The critical determination at this point is to determine what exists now. This is necessary to provide a basis for later comparison--to compare the results of the chosen monitoring plan with the recognized datum established by the baseline data acquisition task.

It is unlikely that any area will initially have baseline data sufficient to make a complete environmental assessment for ground water monitoring. Therefore, during the first phase, each data category should be evaluated for completeness. Some questions which might be asked are: is the stratigraphy known in sufficient detail? are the hydrologic characteristics adequately defined? is the distribution of wells sufficient for adequate monitoring, especially in terms of depth, distribution and sample density? are any wells particularly precarious with respect to becoming polluted or providing a potential pollutant pathway? is the temporal distribution of historic chemical data sufficient to establish patterns of temporal variation or consistency in water quality?

Determination of data completeness will include consideration of current regulations by EPA and others, as well as knowledge of current and potential ground water use in the area. Given the level of available data, and the knowledge these data have supplied, the investigators are in a good position to evaluate which parameters are necessary to supplement the existing data and which can be deferred. After the initial data gathering, synthesis and interpretation, a program should be set up to supply the necessary supplemental data. The limitations of the existing data should be explicitly defined.

To monitor for changes in ground water characteristics that may occur during geothermal development and injection, the baseline conditions that must be established include:

a. chemical characteristics of nongeothermal ground water, geothermal ground water, and surface waters;

b. geology and hydrology of the area;

c. location, well use and well completion data for all wells in and around the geothermal site; and

d. mechanics and characteristics of the geothermal system.

These are discussed in the following subsections. Many of the individual parameters that must be synthesized in this analysis are summarized in EPA Administrators Decision Statement No. 5 (Appendix A). Table 3.1 summarizes desired subsurface baseline data elements and methods applicable for their determination. Applications of borehole logging to baseline data acquisition are discussed in Section 4.

3.1.1 Chemical Characteristics of Waters

Adverse changes in the chemical characteristics of ground water provide the prima facie evidence of degradation. Hence, determination of the characteristics is one of the most important data sets that will be developed in this phase of study. Data must be collected for all waters in the area, including geothermal and nongeothermal ground water, surface water, and any other disposed water. The goal of this data collection is to establish for each water type (including industrial, municipal and agricultural releases):

1) chemical characteristics;

2) three-dimensional (spatial) distribution;

3) natural temporal variations or cycles;

TABLE 3.1 SUMMARY OF DESIRED SUBSURFACE BASELINE DATA ELEMENTS AND METHODS AVAILABLE FOR THEIR EVALUATION (modified from TEMPO, 1973)

Baseline Data Element	Methods Available for Evaluation
Porosity	Core tests; electric, radioactive and sonic logs
Permeability	Core tests; pumping or injection tests; injectivity profiles; electric, nuclear and sonic logs
Fluid pressures in formations	Drill stem tests; water-level measurements
Water quality	Sampling and analysis; electric and nuclear logs
Thickness and character of geologic formations	Drill time logs; drilling samples; cores; electric, radioactive, caliper and televiewer logs
Mineral content of formations	Analysis of drilling and core samples
Temperature of formations	Temperature log
Amount of flow into various horizons	Injectivity profile
Identification and extent of aquifers, aquitards and structural features	Geologic mapping; drill cores and drillers logs
Piezometric surfaces	Well canvass and ground water-level measurements
Hydrologic budget	Synthesis of precipitation, evaporation and evapotranspiration, stream flow, artificial inflow and outflow data

4) in conjunction with the geologic data, chemical reactions and changes as the water flows through subsurface materials; and

5) mixing relationships, if any, of these waters, and where mixing occurs.

The consistency and accuracy of chemical sampling plays a critical role and is discussed below. The next subsection describes a sample baseline water chemistry investigation for Imperial Valley, California. It provides an illustration of an approach to achieving the goals stated above.

Sample Collection and Chemical Analysis--

Sampling and analysis of waters and geothermal effluents is a specialized field. Some of the more relevant references are: Brown, et al. (1970); Wood (1976); Reed (1975); Ellis, et al. (1968); Presser and Barnes (1974); EPA (1974); EPA (1976); EPA (1978); American Public Health Association (1977); and Watson (1978). These works detail most of the step-by-step procedures that should be followed in collecting and analyzing water and geothermal effluent samples. The document by Shannon, et al. (1978) is a standard methods manual specifically for sampling and analysis of geothermal fluids.

The following factors can influence the consistency and accuracy of the chemical analysis:

a) parameters determined at the time of sampling;

b) time interval between sample collection and analysis;

c) type of sample containers;

d) method of sample preservation;

e) procedure for sample collection;

f) analytic techniques;

g) representativeness of the sample.

To get an accurate measure of certain volatile constituents and physical properties it is important to determine their values at the time of sampling. Parameters that should be measured for all waters at time of collection are pH, temperature, specific conductance, and content of carbonate, bicarbonate, Eh and dissolved oxygen (Wood, 1976). For geothermal waters, aqueous carbon dioxide, aqueous hydrogen sulfide, aluminum and ammonia should also be determined (Reed, 1975; Presser and Barnes, 1974).

For accurate representation of the original chemical species, the time between sample collection and analysis should be kept to a minimum. The longer the sample is stored the greater the chance for chemical and physical reactions in the sample bottle, such as oxidation, reduction, precipitation, adsorption and ion exchange. Iron is a particularly troublesome component in this respect because it tends to oxidize and precipitate (Brown, et al. 1970, p. 14; Presser and Barnes, 1974, p. 2).

The type of sample container and its preparation can influence the accuracy and stability of the sample. Current trends are towards use of polyethylene, Teflon or other plastic containers, although Presser and Barnes (1974) note that plastic bottles are permeable to oxygen. In collecting geothermal samples, care should be taken not to use soft-glass bottles (citrate of magnesia type) when collecting silica samples. In general, the nature of the solutions will influence the rate and types of materials dissolved from the container (Brown, et al. 1970). Each sample container must be cleaned properly before use.

Samples require certain types of preparation to ensure minimal chemical changes during shipping and storage. Brown, et al. (1970, pp. 16-17) recommend collecting four samples from each location: one that is filtered immediately upon collection, one filtered and acidified, one unfiltered and settled, and one unfiltered and well mixed. Each would be analyzed for different groups of constituents. The filtered, untreated sample would be tested for TDS, halogens, alkali metals, boron, nitrogen (nitrate and nitrite), phosphorus, selenium, silica and sulfate. The second sample would be analyzed for alkaline earth metals, alkali metals, transition metals, aluminum, arsenic and lead. The third sample would undergo tests for acidity, alkalinity, calculated carbon dioxide, color, and laboratory pH. Analysis of the fourth sample would be for ammonia, organic nitrogen, chemical oxygen demand, cyanide, phosphorus, suspended solids, total volatile solids and turbidity. If the ammonia determination is made in the field it may not be necessary to collect this fourth sample for geothermal fluids.

Additional specially treated samples may be necessary for specific determinations or analysis. One of these is a diluted sample for silica analysis. The geothermal fluid would be diluted (e.g., 10:1) with distilled water to minimize the possibility of silica precipitation upon cooling. This type of sample would be very important for silica geothermometer determinations in the exploration phase of a geothermal development and for anticipation of scaling in the development phase.

Sample collection procedures must be specified and consistently applied. These are fairly straightforward for most nongeothermal surface and ground water and are well outlined in several of the previously cited references. With geothermal fluids, a problem arises in collecting a representative sample. To obtain a representative sample from a superheated geothermal source, most investigators recommend collecting both liquid and vapor samples. Techniques used for such sampling are discussed in detail in Ellis, et al. (1968); Truesdale and Pering (1974); Giggenbach (1976); Hill and Morris (1975); EPA (1976); EPA (1978); Finlayson (1970); and Watson (1978).

In sampling hot springs, geysers, etc. use of a small hand or battery-operated pump with a long tube that can be inserted in the hot water is often convenient. This procedure will allow the sampler better access to the part of the manifestation that would provide the most appropriate sample.

Although the methods used in water analyses are fairly well standardized the accuracy of analytic results should not be taken for granted. Studies have shown significant inconsistencies in analytic results from reputable laboratories (Ellis, 1976; Watson, 1978). Hence, it is always advisable in any sampling program to submit replicates, spikes, blanks and splits. Consistent results from these analyses give confidence that the laboratory's results are accurate and reproducible. Sometimes it may be advisable to submit these samples to a referee laboratory to resolve discrepancies.

A sample is only a small fraction of the water body being sampled. Hence, it is important to ensure that this sample is a true representation of the entire water body being sampled. For a pumping well it should be collected close to the wellhead. For a surface water sample the condition and activity of different parts of the water body must be considered before sampling.

A sample collected closer to the wellhead will have less opportunity for contamination than one collected farther away. For example, in most domestic wells the water is stored in metal storage tanks and flows through metal pipes before it gets to the tap. This storage and conveyance can introduce elements to the water that are not representative of aquifer conditions.

A sample from a pumped or flowing well will be more representative of the aquifer fluid than a sample that is simply bailed from a well. Hence, it is always preferred to pump an unused well before sampling. If the well does not have a pump, a portable submersible pump can be used. If aeration of the sample is not a critical factor, a shallow well can be pumped using an air stream from a small portable gas-driven paint sprayer compressor.

A surface water body such as a spring should be sampled as close to its source as possible. For some other water bodies it may be necessary to mix samples from different parts to produce a representative sample.

For most of the historical data used in the baseline data acquisition it will be impossible to determine many of the previously discussed factors that affect the resulting chemical data. Therefore, even though the data can be used in attempting to decipher temporal and spatial patterns, it would be desirable to start collecting baseline chemical data as soon as possible in a consistent, prescribed, reproducible manner. This would allow direct comparisons between consistent sets of chemical data collected before development begins and after development has commenced.

Water Chemistry Baseline Data Acquisition and Synthesis, Imperial Valley, California--

An example of how a baseline data acquisition program may approach the five goals mentioned previously is described in Geonomics (1978a and 1978b). These two reports comprise a baseline data acquisition and subsurface environmental assessment based on historical data for the Imperial Valley, California. A summary of selected aspects of the program follows. It is included to provide one suggested approach.

Imperial Valley contains six Known Geothermal Resource Areas (KGRAs) (Fig. 3.1). Imperial Valley comprises the regional ground water regime for East Mesa KGRA and water chemistry data have been collected for the entire valley. The regional picture provides the framework for understanding local hydrologic patterns.

The first step in this program was collection of all available historical water chemistry data. Next, several graphic techniques were used to synthesize and interpret the hundreds of chemical analyses. These were Stiff diagrams, Langelier-Ludwig plots and single chemical parameter contour surfaces. These techniques are described in Section 3.6.2 on data synthesis. The results of the study are summarized below.

Chemical characteristics of Imperial Valley waters--Five chemically distinct types of water were identified (Fig. 3.2) from plotting Stiff diagrams of the historical data on maps of Imperial Valley. They are:

1) Simple sodium chloride water. This water has a TDS range from somewhat over 700 mg/l in the southeastern portion of the valley to over 13,000 mg/l in the central portion. One oil

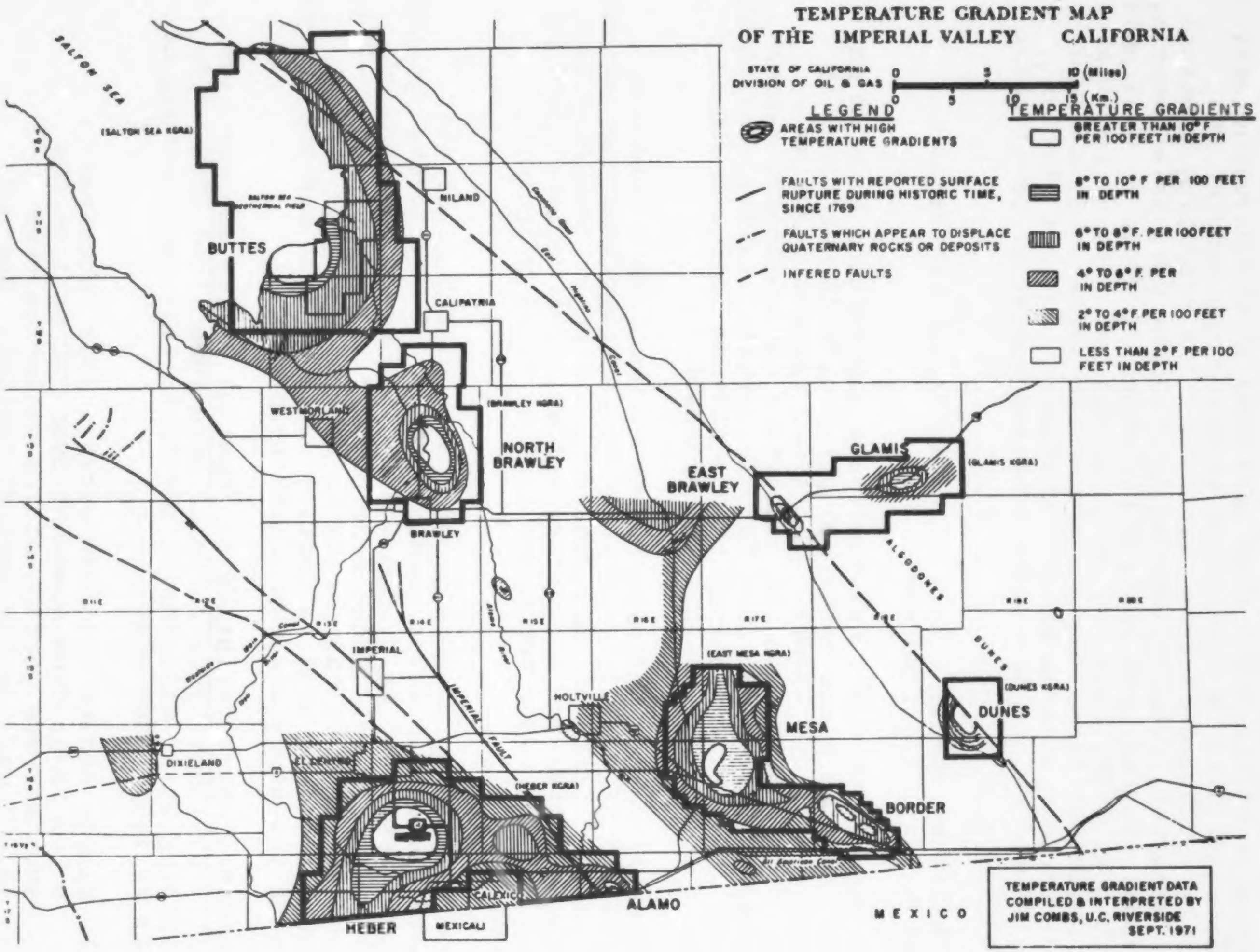
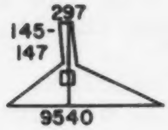
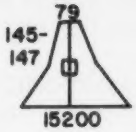

TEMPERATURE GRADIENT MAP
OF THE IMPERIAL VALLEY CALIFORNIA
STATE OF CALIFORNIA DIVISION OF OIL & GAS
0 5 10 (Miles)
0 5 10 15 (Km.)
LEGEND
AREAS WITH HIGH TEMPERATURE GRADIENTS
FAULTS WITH REPORTED SURFACE RUPTURE DURING HISTORIC TIME, SINCE 1769
FAULTS WHICH APPEAR TO DISPLACE QUATERNARY ROCKS OR DEPOSITS
INFERED FAULTS
TEMPERATURE GRADIENTS
GREATER THAN 10° F PER 100 FEET IN DEPTH
8° TO 10° F PER 100 FEET IN DEPTH
6° TO 8° F. PER 100 FEET IN DEPTH
4° TO 6° F. PER IN DEPTH
2° TO 4° F PER 100 FEET IN DEPTH
LESS THAN 2° F PER 100 FEET IN DEPTH
SALTON SEA
(SALTON SEA KGRA)
SALTON SEA GEOTHERMAL FIELD
BUTTES
NILAND
CALIPATRIA
WESTMORLAND
(BRAWLEY KGRA)
NORTH BRAWLEY
BRAWLEY
EAST BRAWLEY
GLAMIS
(GLAMIS KGRA)
ALGODONES
DUNES
(DUNES KGRA)
IMPERIAL
IMPERIAL FAULT
HOLTVILLE
(EAST MESA KGRA)
MESA
BORDER
DIXIELAND
EL CENTRO
(HEBER KGRA)
CALEXICO
HEBER
MEXICALI
ALAMO
MEXICO
TEMPERATURE GRADIENT DATA COMPILED & INTERPRETED BY JIM COMBS, U.C. RIVERSIDE SEPT. 1971

Figure 3.1 Temperature gradient map showing Known Geothermal Resource Area (KGRA) locations in Imperial Valley, California. (Palmer, 1975)

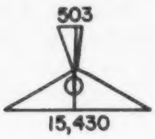
A. Typical Simple Sodium Chloride Water


297
145-
147
9540

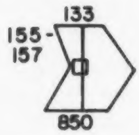
B. Typical Sodium Chloride Water with High Sulfate and/or Magnesium


79
145-
147
15200

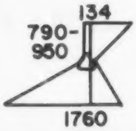
C. Typical Sodium Chloride Water with High Calcium



D. Typical High Sulfate Water


133
155-
157
850

E. Typical Sodium Bicarbonate Water


134
790-
950
1760

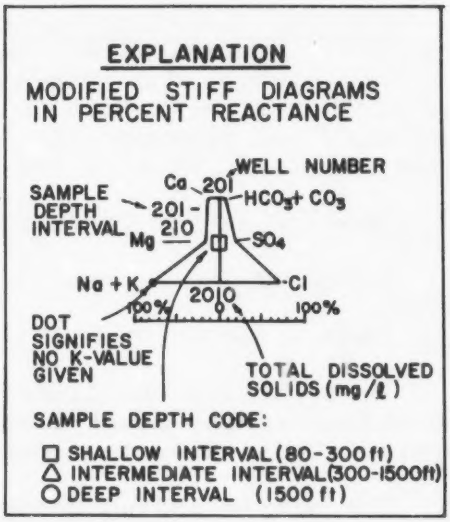

EXPLANATION
MODIFIED STIFF DIAGRAMS IN PERCENT REACTANCE
WELL NUMBER
Ca
201
SAMPLE DEPTH INTERVAL
201-
210
Mg
HCO3+ CO3
SO4
Na + K
Cl
2010
100%
0
100%
DOT SIGNIFIES NO K-VALUE GIVEN
TOTAL DISSOLVED SOLIDS (mg/ℓ)
SAMPLE DEPTH CODE:
□ SHALLOW INTERVAL (80-300 ft)
△ INTERMEDIATE INTERVAL (300-1500 ft)
○ DEEP INTERVAL (1500 ft)

Figure 3.2 Modified Stiff diagrams for characteristic Imperial Valley ground waters. (Geonomics, 1978a)

test well, more than 4000 m (13,000 ft) deep, contained a sodium chloride water with almost 53,000 mg/l.

2) Sodium chloride water with high sulfate and/or magnesium. This water is typical of Salton Sea water and ranges from 1,490 mg/l TDS in the shallow depth zone just south of the Salton Sea to over 37,000 mg/l in the sea itself.

3) Sodium chloride water with high calcium. These are all geothermal waters with TDS contents from about 12,000 to over 300,000 mg/l.

4) High sulfate water. This water is typical of the Colorado River. It has TDS contents under 1,000 mg/l.

5) Sodium bicarbonate water. This water is typical of the intermediate depth artesian aquifer. It contains from less than 300 mg/l TDS in fresh waters flowing off the Peninsular Range into the shallow aquifer in the southwestern corner of the valley, to over 2,600 mg/l in the intermediate depth zone under the northern part of East Mesa.

Spatial distribution of water types--The ground water regime in Imperial Valley was divided into three depth zones for this study. The near-surface upper 24 m (80 ft) was excluded from the natural baseline data because of possible contamination from percolating agricultural return waters. Hence, starting at 24 m (80 ft) these depth zones are defined as:

Shallow - from 24 to 91 m (80 to 300 ft),

Intermediate - from 91 to 457 m (300 to 1,500 ft), and

Deep - deeper than 457 m (1,500 ft).

To determine the distribution of ground water in these subsurface zones, Stiff diagrams were plotted on maps of Imperial Valley for each depth zone.

The simple sodium chloride water (Fig. 3.2[A]) occurs in all three depth zones, but there is a statistically significant correlation of this water with the shallow depth zone. Water of this type is fairly well distributed throughout the area east of the New River within the shallow depth zone. The sodium chloride water occurs very sparsely in the intermediate and deep aquifers.

The sodium chloride water with high sulfate and/or magnesium (Fig. 3.2[B]) is present in only the shallow and intermediate depth zones. In the shallow zone it occurs near inlets in the southern portion of the Salton Sea and is typical of Salton Sea water. Similar type waters with high sodium chloride and notable sulfate occur in the shallow and intermediate depth zones in southeastern Imperial Valley. A few samples of similar waters occur in the shallow depth zone to the west and northwest of El Centro and in the northernmost area of the intermediate depth zone samples.

The sodium chloride water with high calcium (Fig. 3.2[C]) occurs only in the deep aquifer. It occurs in the Cerro Prieto, Heber and Salton Sea geothermal fields and there appears to be a distinct north-south trend between these occurrences. It is possible that there is a hydraulic connection between these waters but most likely they are all undergoing a similar chemical reaction.

The high sulfate waters (Fig. 3.2[D]) are typified by average Colorado River water. This water occurs mainly in the shallow aquifer and has a statistically significant correlation with it. It occurs mainly beneath and very close to canals in the southeastern portion of Imperial Valley, obviously a result of leakage of river water from the canals. One sample of this water occurs in the intermediate depth zone directly beneath the All-American Canal and one occurs in the deep depth zone, in the Dunes geothermal field, just to the northwest of the Coachella Canal.

Although the sodium bicarbonate waters (Fig. 3.2[E]) in Imperial Valley occur in all three depth zones there is a marked statistically significant correlation of this type of water with the intermediate depth zone. Almost 80% of the samples of this type of water occur in the intermediate depth zone. It is largely confined to the artesian aquifer area, between the Alamo River and the East Highline Canal. Four of the samples of this water type also occur in the shallow depth zone just west of the Elsinore fault trace, in the southwestern corner of Imperial Valley.

Two distinct trends can be noted in the shallow depth zone. First, ground water increases in salinity from about 800 mg/l in the southeastern corner of the valley to over 15,000 mg/l approaching the center of the valley and the Salton Sea. The salinity then decreases to the west. This trend is well illustrated by the schematic surface of specific conductance values (Fig. 3.3).

Secondly, water chemistry changes from a low TDS, high sulfate water in the southeastern corner of the valley, to a

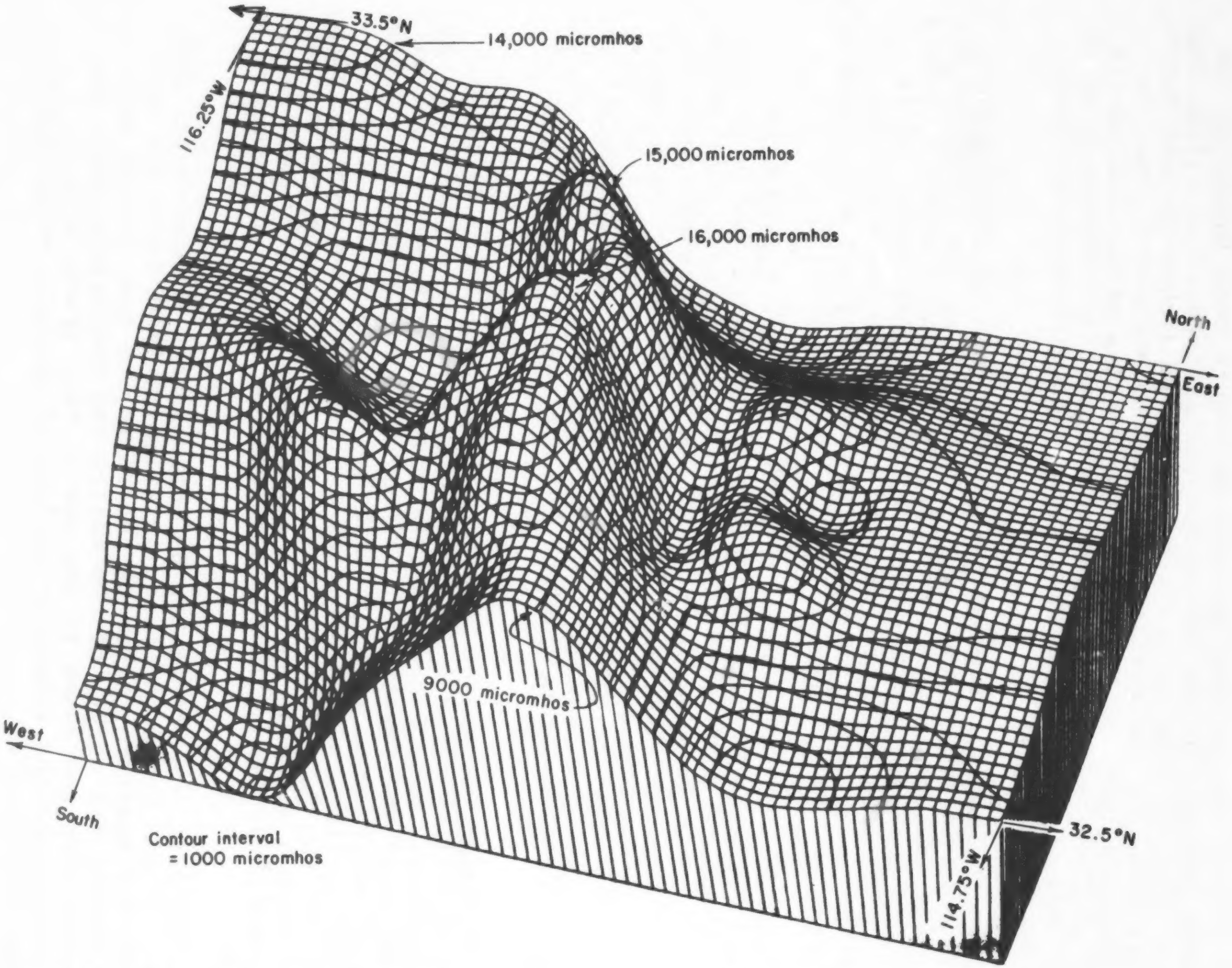


Figure 3.3 Schematic surface of specific conductance values for Imperial Valley ground water. (Geonomics, 1978a)

simple sodium chloride water in the East Mesa area, to a sodium chloride water with high sulfate and/or magnesium and high TDS approaching the Salton Sea.

Temporal variations--Temporal variations in surface and ground water quality must be considered. Seasonal variations will be found in surface water quality and will probably be reflected in ground water quality. Unfortunately, historic data for this type of correlation are often quite limited.

Colorado River water at Yuma has varied in TDS from less than 500 mg/l to a current level of 700 to 800 mg/l. This trend of increasing salinity will continue as more water is diverted from the river above Yuma for irrigation.

The salinity of the Salton Sea has varied greatly through its history, depending on variations of sea volume, mineral content and quantity of inflowing waters and precipitation of saturated ions. It has ranged from about 3,600 mg/l in 1907 to 40,000 mg/l in 1925 and it is currently around 36,000 mg/l. The highest salinity was measured in 1936 at 213,000 mg/l.

A few wells in Imperial Valley produced historic chemical data, but not enough for meaningful analysis. The most important trend noted was anomalous analytical results between two ends of a sampling period. Well No. 393, a shallow well in the extreme southwestern Imperial Valley is an example. The samples for 1967 and November 1972 are quite similar sodium carbonate chloride waters with a somewhat smaller calcium content in November 1972 than in 1967. The TDS content was 360 mg/l in 1967 and 341 mg/l in November 1972. However, a sample taken in July 1972 exhibited distinctly higher sulfate and a TDS content of 455 mg/l. This example again points out the necessity to remain aware of possible undetected changes in water characteristics between sampling periods and to specify adequate sample intervals for each site.

Mixing relationships--Langelier-Ludwig (L-L) diagrams are very useful for detecting the origin of waters and mixing relationships. In the Imperial Valley study distinct groupings occur. Although there is some scatter, a definite concentration of shallow interval samples occurs in a zone with greater than 90% reactance* (SO_4+Cl). Between approximately 55 and 85% reactance (Na+K) (Fig. 3.4) of intermediate depth samples occur

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* Percent reactance =

$$\frac{\text{anion species (in milliequivalents/liter [meq/l])}}{\text{sum of all anion species (in meq/l)}}$$

or $$\frac{\text{cation species (in meq/l)}}{\text{sum of cations (in meq/l)}}$$

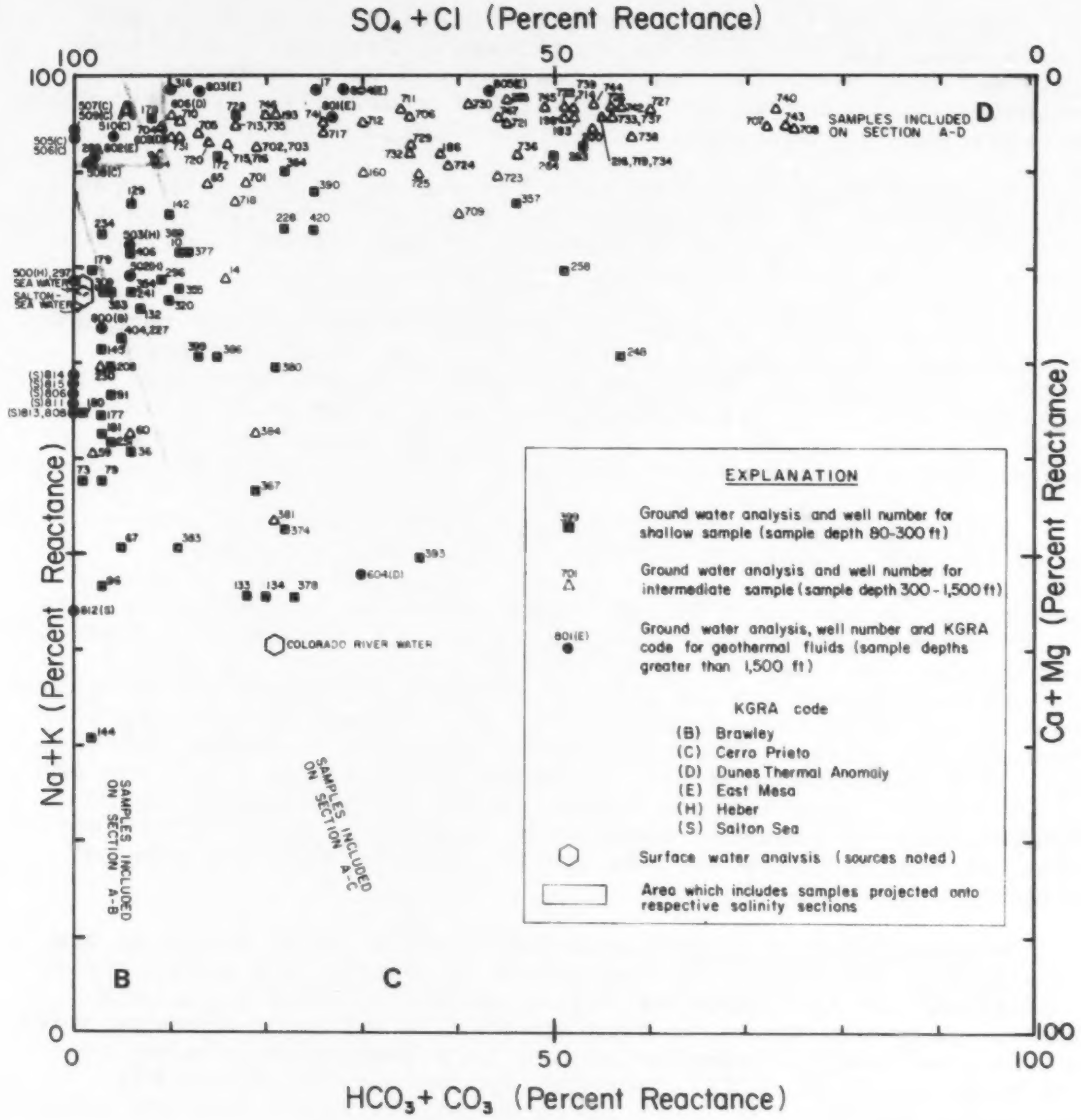

Figure 3.4 Langelier-Ludwig diagram for ground water data in Imperial Valley, California. (Geonomics, 1978a)

in a zone with greater than 90% reactance (Na+K) and between approximately 25 to 95% reactance (SO_4+Cl). Distinct clusters in this zone occur between 25 and 30 and between 40 and 52% reactance (SO_4+Cl).

Most of the geothermal waters plot above 98% reactance (SO_4+Cl) or (Na+K) (Fig. 3.4). The Salton Sea wells occur at 100% reactance (SO_4+Cl) and between 64 and 69% reactance (Na+K). Three of the East Mesa wells plot at 98% reactance (Na+K) and between 57 and 87% reactance (SO_4+Cl).

Concentration by evaporation can be seen in the lower portion of an L-L diagram salinity section (Fig. 3.5) where the Salton Sea geothermal fluid shows a relatively constant ratio of chemical constituents steadily increasing in salinity. Salinity section A-D (not shown) shows a very dense cluster of points in a triangular pattern. This is suggestive of complete mixing of the three waters having compositions represented by the apexes of the triangular patterns. These are: a fairly pure water of low salinity, a sodium bicarbonate water of about 60 milliequivalents per liter (meq/l) salinity, and a sodium chloride water of about 110 meq/l salinity.

Chemical reactions with subsurface materials--Some general chemical changes were previously noted for the evolution of Imperial Valley water in the "Spatial Distribution of Water Types" subsection. In addition, to aid in tracing the possible genesis of ground waters in Imperial Valley, chemical reactions that could alter Colorado River source water were considered by Olmsted, et al. (1973).

In this approach recent Colorado River water is assumed to undergo certain common geochemical reactions in combination with various degrees of evaporative concentration. The results of these reactions are computed, providing a set of known chemical causes and effects on Colorado River water. By comparing these known changes with analyses of actual waters it is possible to get a suggestion of the processes the water has undergone in the ground. A sample of some of these changes, as shown by modified Stiff patterns, is presented in Fig. 3.6. Since many people may be accustomed to seeing Stiff patterns plotted in milliequivalents per liter, this figure also compares modified Stiff patterns plotted in percent reactance with those plotted in milliequivalents per liter to illustrate the characteristics of these different representations.

The first chemical change shown, that of simple evaporation, shows the percent reactance modified Stiff pattern remaining the same size and shape with increasing concentration (Fig. 3.6). The modified Stiff pattern plotted in milliequivalents

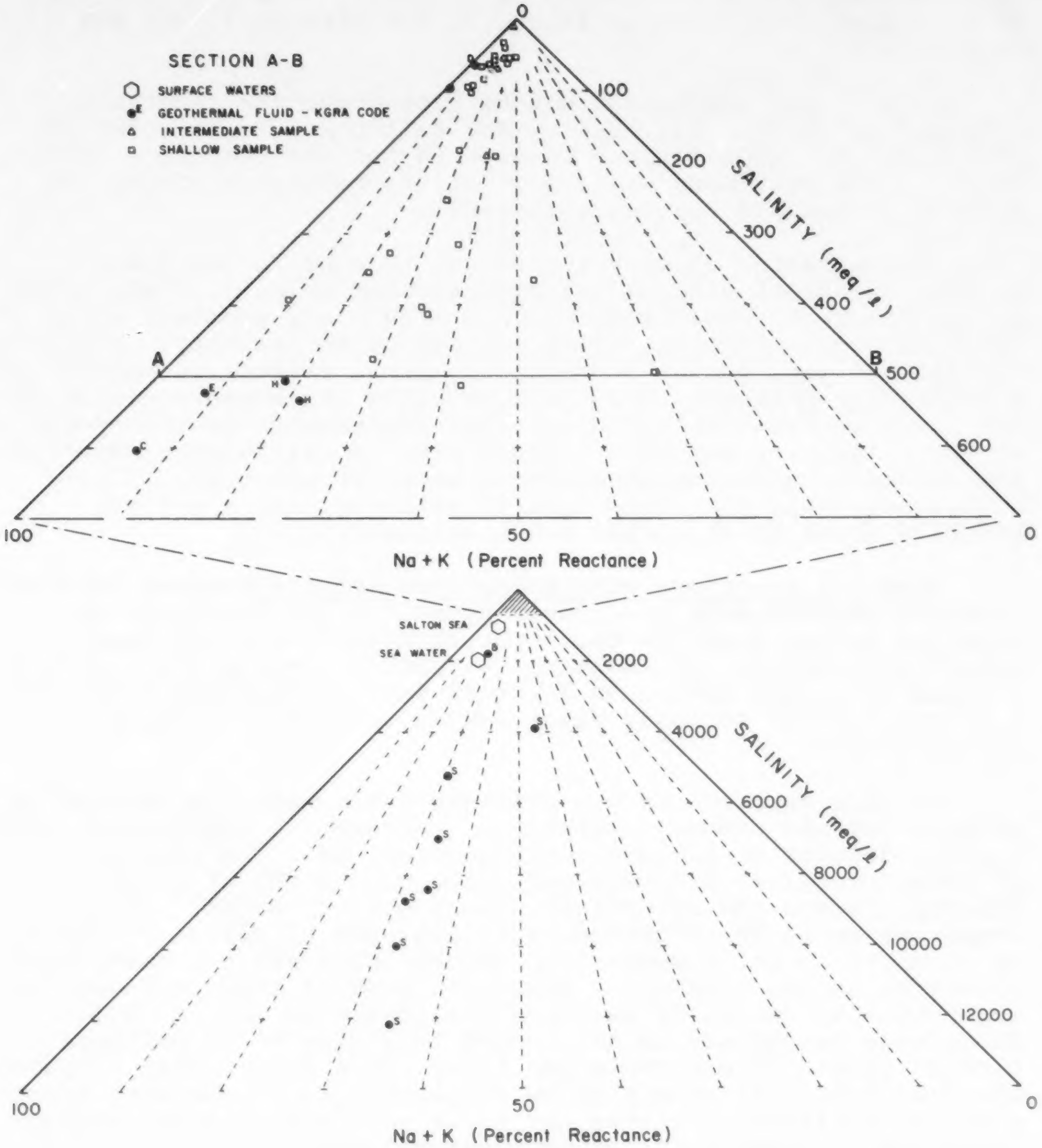

Figure 3.5 Salinity section A-B from Langelier-Ludwig diagram for ground water data in Imperial Valley, California. (Geonomics, 1978a)

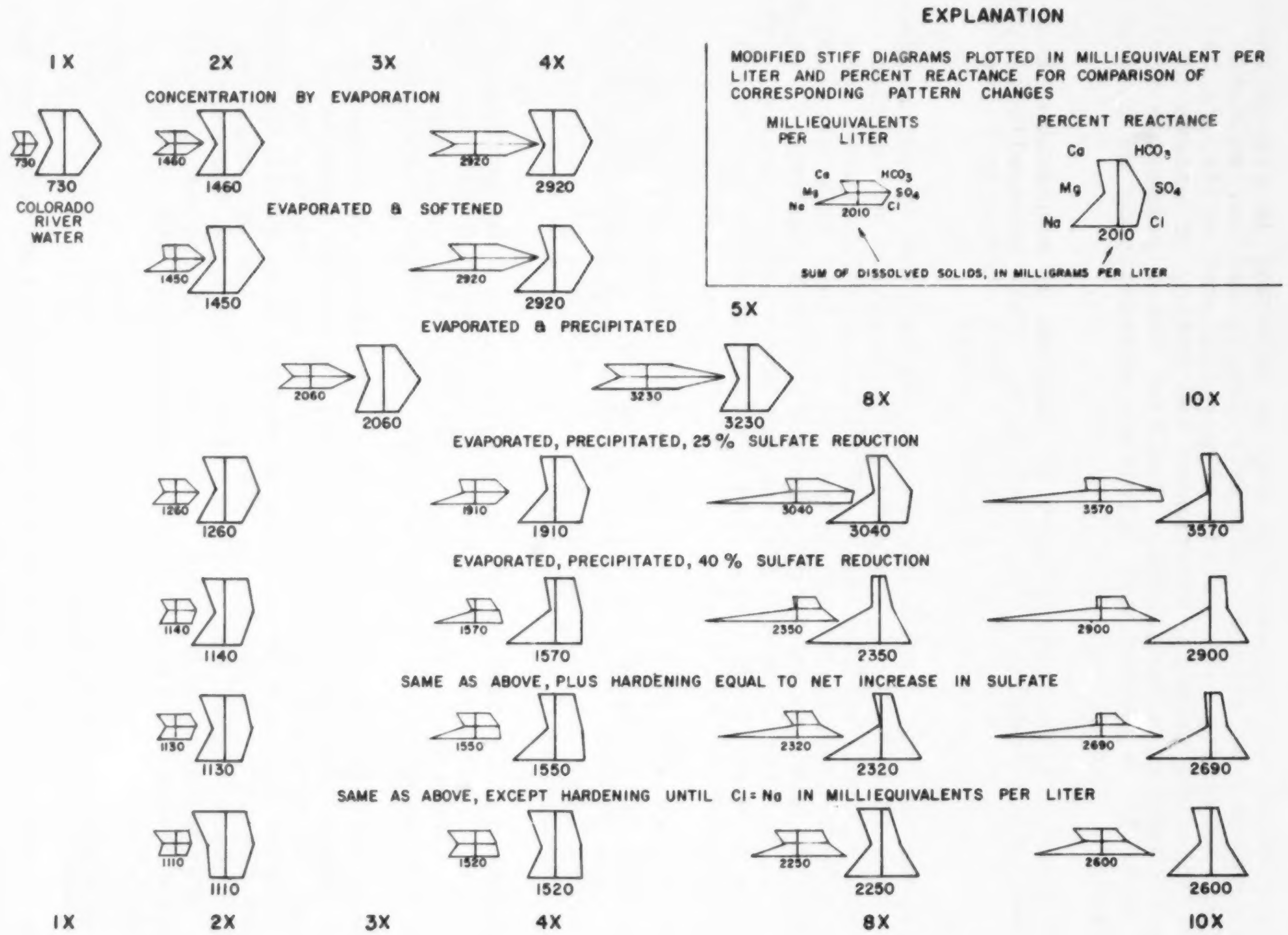
EXPLANATION
MODIFIED STIFF DIAGRAMS PLOTTED IN MILLIEQUIVALENT PER LITER AND PERCENT REACTANCE FOR COMPARISON OF CORRESPONDING PATTERN CHANGES
MILLIEQUIVALENTS PER LITER
PERCENT REACTANCE
Ca
Mg
Na
HCO3
SO4
Cl
2010
SUM OF DISSOLVED SOLIDS, IN MILLIGRAMS PER LITER
1X
2X
3X
4X
5X
8X
10X
CONCENTRATION BY EVAPORATION
730
COLORADO RIVER WATER
1460
2920
EVAPORATED & SOFTENED
1450
2920
EVAPORATED & PRECIPITATED
2060
3230
EVAPORATED, PRECIPITATED, 25 % SULFATE REDUCTION
1260
1910
3040
3570
EVAPORATED, PRECIPITATED, 40 % SULFATE REDUCTION
1140
1570
2350
2900
SAME AS ABOVE, PLUS HARDENING EQUAL TO NET INCREASE IN SULFATE
1130
1550
2320
2690
SAME AS ABOVE, EXCEPT HARDENING UNTIL Cl=Na IN MILLIEQUIVALENTS PER LITER
1110
1520
2250
2600

Figure 3.6 Modified Stiff diagrams representing hypothetical analyses of ground water resulting from specified chemical changes in Colorado River water. (modified from Olmsted, et al. 1973).

per liter maintains a similar shape but elongates markedly with increasing concentration due to evaporation.

Other chemical changes that may be expected in ground water in this area are softening, carbonate precipitation, sulfate reduction, hardening, resolution of precipitated salts, oxidation of dissolved organic substances and mixing of waters of different chemical composition. The last three processes would be difficult to represent and calculate meaningfully so they are not presented in Fig. 3.6.

Softening is the replacement of calcium or magnesium, the hardness-causing constituents, by sodium. This generally occurs by cation exchange with clay minerals. This change is illustrated in the second line of diagrams in Fig. 3.6.

When water with high bicarbonate and calcium or magnesium content is sufficiently evaporated, precipitation of calcium or magnesium bicarbonate occurs. To distinguish between loss of calcium and magnesium from softening and loss from carbonate precipitation one can look for a reduction in bicarbonate, which occurs with carbonate precipitation but not with softening. This process is labeled "evaporated and precipitated" on the third line of diagrams in Fig. 3.6.

Sulfate reduction is believed to be a major process occurring in Yuma area ground water, an area very similar to Imperial Valley. The process of sulfate reduction is poorly understood but is known to be organic. The last four lines of diagrams in Fig. 3.6 involve sulfate reduction.

Hardening, the reverse of softening, is a base-exchange process where sodium is replaced by calcium or magnesium. Like softening, hardening results from reactions with clay minerals. The last two lines of diagrams in Fig. 3.6 involve hardening.

Comparison of the different chemical reactions shown in Fig. 3.6 shows that the TDS content may be a poor measure of the amount of evaporative concentration of the sample. The chemical reactions the sample has undergone also significantly influence the TDS. This can be seen in Fig. 3.6 by comparing the TDS content (2,920 mg/l) of the sample with 4X "concentration by evaporation" with that (2,900 mg/l) of the sample with 10X concentration by "evaporated, precipitated, 40% sulfate reduction".

3.1.2 Geology and Hydrology

The goals of the geologic and hydrologic investigation are to determine:

1) distribution of aquifers and aquitards, including their lithology and mineralogy;

2) ground water flow rates and patterns, water levels, transmissivities, recharge and discharge areas and hydrologic budget; and

3) the location and extent of structural or stratigraphic features that may provide potential pollutant pathways and boundaries.

A fairly complete hydrologic and geologic investigation will be necessary to make these determinations. Particular emphasis must be placed on determining the properties of the injection horizon and its confining strata. In most cases the geothermal reservoir will be the injection horizon. Again, this task should start with existing data from the literature, private or governmental agency files or reports, personal contacts, researchers in the area, etc. These data should then be analyzed in the context of the three goals mentioned above. One approach to achieving these goals is outlined below.

Distribution of Aquifers and Aquitards--

Ideally, the areal extent and depth of aquifers and aquitards as well as lithology and mineralogy can be directly derived from a closely spaced array of geologic and geophysical well logs. However, aquifer and aquitard units often must be defined indirectly from limited well log data, with substantiation from geologic maps and cross sections.

Extrapolations from only geologic data can lead to complications. For example, in attempting to correlate a geologic formation with a hydrologic unit (aquifer or aquitard) one may find that a geologic formation, as mapped, does not coincide with a hydrologic unit. In addition, the geologic data may not provide sufficient subsurface detail for the hydrologic investigation, especially for units as deep as geothermal reservoirs.

Sometimes the nature of the formations makes definition of specific hydraulic units difficult or impossible. For example, in Imperial Valley, the units are of fluvial, alluvial and lacustrine origin, consisting mainly of interbedded and lensing sandstones and shales. All are cut by myriad fault traces. In this environment, the lack of vertical or horizontal continuity causes difficulty in identifying continuous hydraulic units, and only major discontinuities can be defined.

Detailed vertical lithologic profiles can be derived from the geophysical well logs described in Section 4 and from cores. Rock samples, ideally from cores, are necessary for detailed mineralogic and petrographic determinations. Before cores are available, analyses of rocks from surface exposures of mapped units will have to suffice. An important aspect of this task is determination of the mineralogy of the injection horizon to evaluate possible chemical reactions of the injected fluid with the formation.

Ground Water Flow Rates and Patterns--

This will make up the largest part of the geologic and hydrologic investigation. The determinations to be made in this category include water tables and piezometric surfaces, permeabilities and transmissivities, ground water flow directions and velocities, recharge and discharge areas and hydrologic budget.

Available water table and piezometric surface data should be supplemented by the data that is collected in the water well canvass (see Section 3.1.3). These include maps of ground water elevations and depths for each aquifer in the area. Ground water flow directions can be seen on the ground water elevation maps and hydraulic head can be computed. Implications about permeability and recharge and discharge areas can also be derived, but these extrapolations must be corroborated by further data.

Permeabilities and transmissivities can often be extrapolated from geologic data for sedimentary deposits with intergranular permeability. However, most geothermal areas occur in igneous or metamorphic terranes with fracture permeability, which is much more difficult to estimate. It would be desirable to conduct pump tests for these determinations.

Once the hydraulic head is determined from the water level elevation map and the permeability is found or estimated, the ground water flow velocity can be calculated.

The drainage basin determinations of recharge, discharge and hydrologic budget can be derived from data on precipitation, stream flow, evapotranspiration, soils, land and water use, water level and quantities of water imported. Some of these data will be derived from the water well canvass (Section 3.1.3).

Location of Structural and Stratigraphic Features--

Structural and stratigraphic features can act as potential pollutant pathways and boundaries. Faults play an extremely important role in the hydrologic and geothermal systems. Faults may provide structural control for the location of geothermal reservoirs; they may provide conduits for the lateral and vertical flow of geothermal fluids and fresh ground water; and they can act as aquitards and aquicludes in the hydrologic system. Stratigraphic features such as buried stream channels can also influence ground water flow. Special attention must be paid to the detail, completeness and accuracy of fault locations and other relevant structural and stratigraphic features.

In many areas, the number of located faults is directly proportional to the detail of mapping done in the area, hence the absence of faults on a published map is not necessarily an accurate representation of the actual situation. This is especially true in an area like the Imperial Valley where most fault traces are concealed. Here the detail of the fault traces mapped are in direct proportion to the detail of geophysical surveys conducted (Geonomics, 1978a).

3.1.3 Well and Fluid Discharge Data

Regardless of the amount and comprehensiveness of current and historical well and fluid discharge data the investigators should conduct their own canvass and sampling program of wells and fluid discharge sources (such as individual or municipal waste disposal sites). There are five main reasons for conducting this survey:

1) to determine or supplement hydraulic head distribution data;

2) to establish or supplement ground water and aquifer characteristics in the area with the known procedures for water sampling used in the monitoring plan;

3) to gain firsthand experience in locating, inspecting and sampling the wells in order to judge their potential usefulness as monitoring wells;

4) to learn about abandoned wells in the area and their potential for use in monitoring or providing pollutant pathways; and

5) to identify other industrial, municipal or domestic existing or potential sources of ground water degradation.

The well and fluid discharge canvass should begin with detailed study of well and fluid discharge locations on topographic maps. This would be followed by field verification and investigation of the sites identified on the maps, and a search for additional sites.

Data collected in the field investigation for wells would include as much of the following as possible:

1) well location and altitude;
2) owner;
3) water level;
4) cased depth, well depth;
5) construction, including year drilled, casing diameter, casing material, grouting, packers, perforation types and intervals;
6) drilling logs or other well logs;
7) previous chemical analyses;
8) water and well use (including amount);
9) previous water levels and dates;
10) type of pump;
11) yield of well;
12) water samples for analysis;
13) other relevant observations and impressions.

Preparation of a form outlining all these parameters would help in reducing inconsistencies and omissions in the survey. The goal of this phase is to collect as much information as possible about the wells and their use.

Data similar to that for the water wells should be collected for other fluid discharge sites, including data on waste fluid disposal methods and quantity of wastes disposed. Later, if any of the monitoring wells show water degradation, knowledge of the characteristics of the other potential pollutant sources will help determine if the degradation is caused by the geothermal fluid or another source.

In the next phase maps will be prepared showing the distribution of geothermal wells, nongeothermal wells, and fluid discharges. These maps will show the relationships of ground water use and fluid discharge to the geothermal well locations. Of particular significance is the number, use and depth of wells near and downgradient from the geothermal wells. A sample map for a preliminary water well survey for the East Mesa KGRA

(Fig. 3.7) shows several water wells around and downgradient from the geothermal wells. However, almost none of these wells is used or yields significant quantities of water.

Wells in poor condition that may provide conduits for inter-aquifer pollution may be checked using cement bond, caliper, borehole televiewer and pipe inspection logs (See Section 4). Particular attention should be paid to wells penetrating the deeper aquifers.

3.1.4 The Geothermal System

To consider the interaction of the geothermal system with the nongeothermal ground water regime, both systems must be defined as accurately as possible. Undoubtedly less data will be available for the geothermal system and much of the definition will be based on models and extrapolation.

Aspects of the geothermal system that need to be defined are:

1) the size, shape and boundaries of the reservoir;
2) the temperature and pressure of the reservoir fluid;
3) the type of system;
4) the chemistry of the reservoir fluid;
5) the lithology and mineralogy of the reservoir; and
6) the recharge source for the reservoir.

This information will provide an idea of how the geothermal system and nongeothermal system may be related in terms of fluid chemistry, geologic structure and rock type, degree of hydraulic connection, and common recharge sources. This information will allow estimation of the resource potential, which will affect the projected development. These parameters are discussed in the following paragraphs.

The size, shape and boundaries of the reservoir may be approximated by geologic, surface geophysical and borehole log data. Various types of resistivity, telluric, magnetotelluric and microseismic techniques have been used in exploration for and definition of geothermal reservoirs. Geologic structural data is often used to define reservoir boundaries. For example, it is hypothesized that the reservoir at Roosevelt Hot Springs, Utah, is bounded by four faults, including the Dome fault to the west, the Negro-Mag fault to the north, a mountain front fault

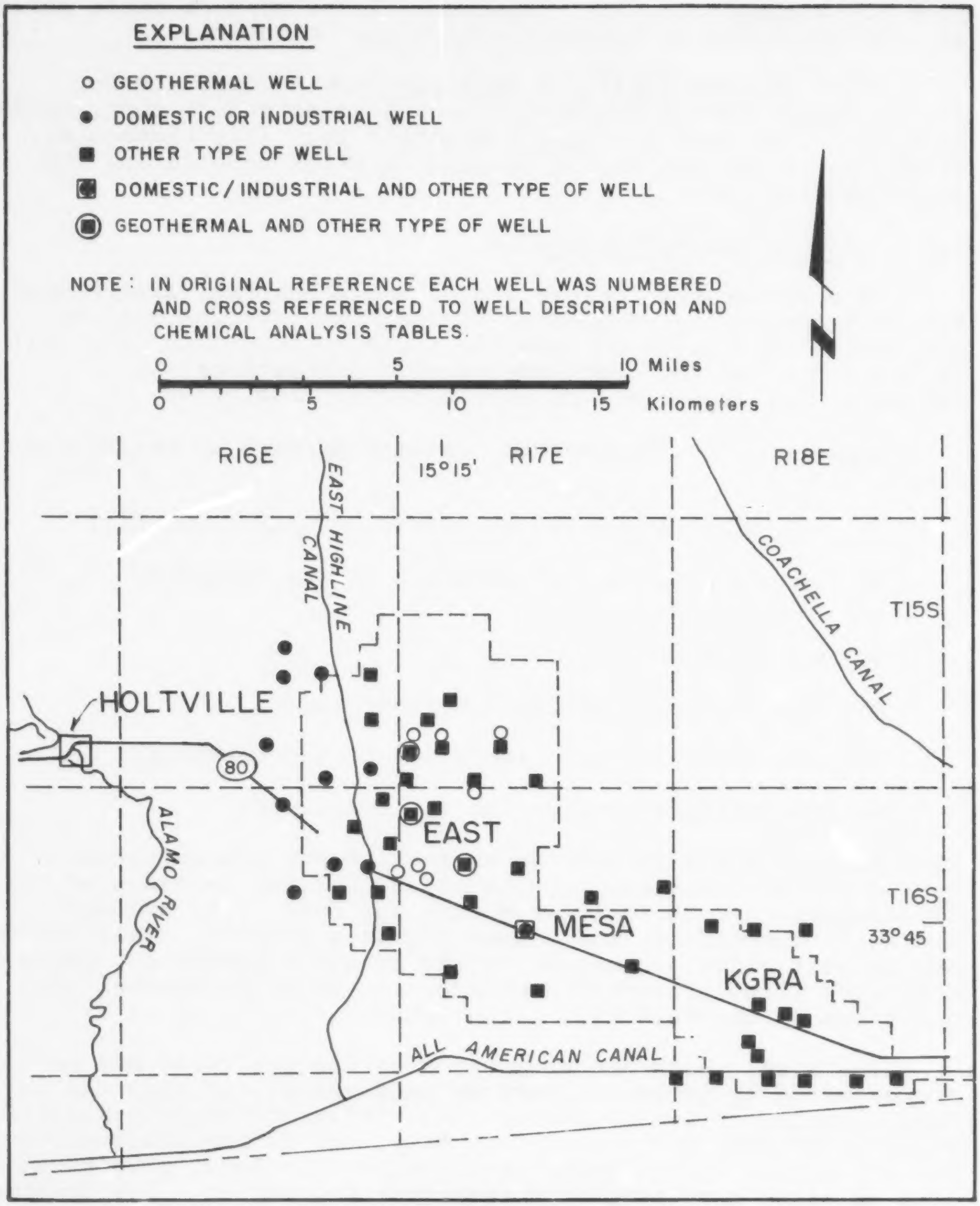
EXPLANATION
○ GEOTHERMAL WELL
● DOMESTIC OR INDUSTRIAL WELL
■ OTHER TYPE OF WELL
DOMESTIC/INDUSTRIAL AND OTHER TYPE OF WELL
GEOTHERMAL AND OTHER TYPE OF WELL
NOTE: IN ORIGINAL REFERENCE EACH WELL WAS NUMBERED AND CROSS REFERENCED TO WELL DESCRIPTION AND CHEMICAL ANALYSIS TABLES.
0
5
10 Miles
0
5
10
15
Kilometers
N
R16E
R17E
R18E
15°15'
EAST HIGHLINE CANAL
COACHELLA CANAL
T15S
T16S
33°45
HOLTVILLE
80
ALAMO RIVER
EAST
MESA
KGRA
ALL AMERICAN CANAL

Figure 3.7 Preliminary survey of wells in and near East Mesa KGRA (modified from Geonomics, 1978b)

to the east, and several smaller faults to the south. However, accurate definition of the reservoir requires many drill holes. Even in The Geysers, California, where over 120 wells have been drilled, the extent of the reservoir remains ambiguous.

The temperature of the reservoir fluid can be estimated by various types of geothermometers applied to geothermal fluids emanating at the surface and to fluids produced from wells. Those based on silica solubility and on sodium-potassium-calcium ratios are the most commonly used (Fournier, et al. 1974; Fournier and Truesdell, 1974). Application of either of these techniques is based on many assumptions about the reservoir and genesis of the fluid. Since the accuracy of the assumptions cannot be verified without detailed drill hole and geologic data, the accuracy of the resulting estimates is questionable. Results from the silica geothermometer are particularly subject to suspicion due to the inability to identify the dissolved silica species. Each silica mineral has a different solubility and the assumption of the dissolved species will determine the temperature computed.

Even temperatures measured in flowing wells will represent only one location and depth for the reservoir. Experience has shown that bottomhole temperatures vary considerably for different wells in liquid-dominated reservoirs. For example, production wells drilled in the Salton Sea field have bottomhole temperatures ranging from less than 200°C (390°F) to over 350°C (660°F) (Palmer, 1975). The variation may be less in steam-dominated reservoirs.

Drill holes are necessary to determine reservoir pressures and to verify the type of system. Although surface geophysical surveys (e.g. gravity) can provide indications of whether the system is liquid- or vapor-dominated, drill hole verification is often necessary.

The chemistry of geothermal fluids in general is discussed in Section 2.5.1 and sampling and analysis are discussed in Section 3.1.1.

Lithology and mineralogy of the reservoir are discussed in Section 3.1.2 on Geology and Hydrology and in Section 4 on borehole logging.

Isotope and tracer studies can aid in determining recharge sources. An isotope study of recharge sources for the Imperial Valley geothermal systems determined that geothermal fluid in all the systems, except the Salton Sea field, is derived from Colorado River water (Coplen, 1972). Much water from the hot springs to the south and east of the Salton Sea is derived from local precipitation. Tracer techniques are discussed in Section 3.4.5.

3.1.5 Projected Development

Knowledge of the size and type of projected development is necessary to estimate:

1) the volume of fluid to be extracted from the reservoir and disposed of by injection or other means; and

2) the chemical and physical changes that the fluid will undergo from production through disposal.

This information is important to predict the effects geothermal development may have on the ground water system. To accomplish this goal the following parameters must be defined:

1) the reservoir development plan; and

2) the proposed heat extraction and power production processes.

The reservoir development plan will specify optimum production and injection rates and well locations. This plan will produce necessary information on how the natural geothermal system will be stressed and if that stress may also influence overlying aquifers.

Ideally, the geothermal reservoir under natural conditions is largely isolated from overlying aquifers. In some areas, however, such as Roosevelt Hot Springs, Utah, the geothermal fluid naturally mixes with some of the overlying ground water, probably as the fluid rises along faults that intersect the overlying aquifers. Stressing the natural reservoir conditions by pumping and injection could increase or decrease the effects of natural mixing or could induce a hydraulic connection between overlying aquifers and a reservoir that was formerly isolated. Evaluation of these effects will be discussed in Section 3.2.

The type of energy use, conversion facility, and waste disposal method will determine the change in temperature and chemistry of the geothermal fluid and the type of monitoring program to implement. In most energy conversion processes the fluid will come out more saline than it started. The actual change depends on the individual process and could vary from minimal to significant. This change must be specified by the process engineers. The chemical characteristics of the post-process geothermal fluid must be compared with those of natural geothermal fluid and nongeothermal ground water. In addition to increased salinity, certain constituents which were in innocuous concentrations prior to energy extraction may reach potentially hazardous levels.

Chemical reactions in the injection well and formation will be influenced by temperature drops between production and injection. Pretreatment of the waste fluid before injection may be necessary to reduce potential scaling, corrosion and formation plugging problems. A detailed overview of geothermal injection technology, including descriptions of the chemical and physical problems that may be encountered, is presented in Section 5.

Spent fluid disposal will most often be by injection and the injection horizon will be specified by the reservoir engineer. If a surface disposal method is chosen, the monitoring plan will have a different focus than if injection is used. This difference will manifest itself in such ways as the depth and spatial distribution of monitoring wells, determination of potential degraded fluid plumes and percolation patterns, etc. Monitoring plans for surface sources are more fully described in Todd, et al. 1976.

Regardless of the disposal method chosen, the "preventive monitoring" philosophy can be applied in the design phases of development. Proper well design, construction, and monitoring will vastly reduce the possibility of leakage through the disposal well (see Section 3.5.4). Preventive measures for surface disposal methods, as well as surface conveyances and facilities used with injection, can also be planned. Possible techniques include pressure monitors with alarms and automatic shut-off valves, small levees around the facility, and an impermeable material placed on or beneath the ground surface.

One additional aspect of projected development is detailed evaluation of the specific geologic and hydrologic conditions of the site, e.g., wells that have been drilled at The Geysers. When landslides started moving, some well casings were sheared causing uncontrolled blowouts. Hence, landslide potential is now a major consideration in planning geothermal facilities at The Geysers. Another example of a site-specific geologic consideration is in Imperial Valley, where subsidence potential must be carefully evaluated because of the widespread network of gravity-fed irrigation canals.

3.2 FORECAST AQUIFER CONDITIONS

Forecasting the interaction between geothermal and non-geothermal aquifers may help avoid potential problems. Baseline data acquisition should provide the data necessary for this task. The goal of this task is to determine the effects of the proposed production and injection plan on the existing ground water system. This analysis will consider the following factors:

1. models of the ground water and geothermal systems;

2. potential pollutant mechanisms and pathways;

3. chemical reactions in the aquifers; and

4. effects of alternative development scenarios.

3.2.1 System Models

Models of ground water and geothermal ground water systems can be fairly simple or very complex. They may involve only a qualitative conceptual framework or a detailed, three-dimensional, multivariable computerized mathematical representation. In a ground water monitoring plan, the goal of any model is to predict the movement of a particular fluid front. No model can be as detailed as a natural system, but the more accurately the model represents the actual field situation, the better it will predict the migration of fluid fronts.

Additionally, all models are based on many assumptions, simplifications and boundary conditions as well as the physical and chemical parameters of the actual system. These factors and limitations must be kept in mind when analyzing the results.

Ideally, the model will predict the effects of geothermal production and injection on the existing ground water system. To accomplish this, the model must incorporate much information about the hydrologic, physical and chemical properties of the system. Because some of these parameters may not be available at the planning stages, the model may later have to be refined. Selection of the most appropriate model will be based on the level of information on subsurface conditions.

In the initial stages of the monitoring investigation, data may be sufficient only for a simple, qualitative conceptual model of the system. Eventually, a model that can evaluate the three-dimensional combination of physical and chemical properties is desirable. This model will include quantification of the spatial and temporal distribution of:

1) hydraulic head;

2) temperature;

3) density;

4) chemical constituents; and

5) effects of geothermal fluid production and injection on the existing ground water system.

With this type of model, various sets of production and injection plans could be put in to evaluate the effect of alternate development scenarios on the ground water system.

Intercomp, Inc. (1976) has developed a transient three-dimensional, subsurface, waste disposal, ground water model that includes evaluation of single-phase fluid flow, convective and conductive heat transfer and mixing of aquifer and injected fluids. This is currently the most comprehensive, publicly available model capable of evaluating a geothermal injection situation. Input data requirements for such a model are quite extensive and require a fairly detailed definition of the system and the physical properties of each component.

A review of developments in ground water modeling over the past decade is presented in Narasimhan and Witherspoon (1977). A survey of ground water modeling in the USGS is presented in Appel and Bredehoeft (1976). This source lists all USGS ground water modeling computer programs and their status of development. Modeling categories range from relatively simple two-dimensional problems of ground water flow to complex three-dimensional models involving fluid mixing and heat gradients.

3.2.2 Potential Pollutant Mechanisms and Pathways

Chemical and thermal pollution of ground water aquifers during injection of waste can result from the following:

1. improperly constructed or deteriorated injection well;
2. improperly constructed, deteriorated or ineffectively abandoned wells nearby;
3. escape of injected fluid from the receiving formation through structural or stratigraphic pathways;
4. hydrofracturing of confining formations with high-pressure injection;
5. accidental spills at the ground surface;
6. percolation from storage ponds (enhanced by higher temperatures);
7. percolation from discharge of mineralized fluids through leaks in surface conveyances which are part of the injection system;
8. chemical migration through confining beds due to osmotic forces.

These potential pathways and mechanisms are discussed below.

Improper construction, deterioration or failure of well seals would allow fluids to flow vertically up or down the well bore, depending on where the failure occurred (Fig. 3.8[A]). Casing failure could occur by corrosion (Fig. 3.8[B]). This mechanism can occur in the injection well or other wells in the area. They may be abandoned, used or infrequently used wells. At The Geysers production wells drilled on landslides have blown out when landslides were reactivated and the downslope movement sheared the well casing.

Fig. 3.9 shows a hypothetical example of a potential escape path for injected fluid through an abandoned well and another well penetrating an aquifer overlying the confining bed of the injection aquifer. This case illustrates an example of an improperly plugged abandoned well, where the cement plug is placed far above the perforated interval of the well. This has allowed fluid to flow upwards in the well bore, through the confining bed, into an overlying aquifer that is penetrated by another well. This pathway could also exist by virtue of deteriorated well seals around the casing or corroded casing. To identify locations where this mechanism may occur it is important to survey, where possible, the condition of all wells in the area that penetrate deeper aquifers. In unplugged wells this may be done by running cement bond logs.

Structural and stratigraphic pathways, such as faults, fractures, ineffective caprock or buried stream channels may allow fluid to travel along pathways not previously recognized (Fig. 3.10). Hydrofracturing of confining formations due to high-pressure injection may also create structural pathways in the form of micro-fractures or joints. Hydrofracturing is discussed in Section 5.5.3.

Accidental spills at the surface, percolation from holding ponds, or leakage from surface conveyances would entail similar pathways. The fluids would percolate from the surface downward directly into the nearer surface aquifers. A spill, if not contained, may also discharge fluid directly to surface streams, lakes or canals.

Osmotic forces can cause slow migration of chemical constituents of the waste fluid to a ground water aquifer through an intervening caprock, which may act as an osmotic membrane. However, pollution due to this effect is anticipated to be minor and insignificant.

Although escape of fluids by any of these mechanisms is of concern, the greatest risk of fluid escape is through the injection well itself (Fig. 3.8) (Talbot, 1972). Currently

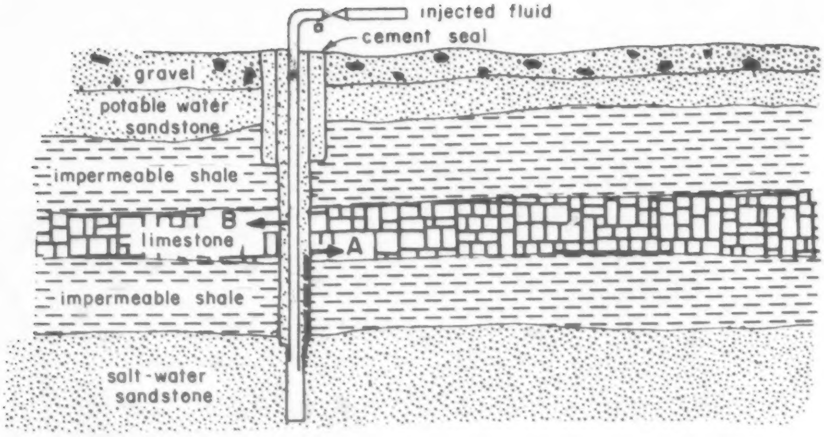
injected fluid
cement seal
gravel
potable water sandstone
impermeable shale
B
limestone
A
impermeable shale
salt-water sandstone

Figure 3.8 Escape of injected fluid through deteriorated cement seal (A) and through hole in casing (B). (modified from U.S. EPA, 1977)

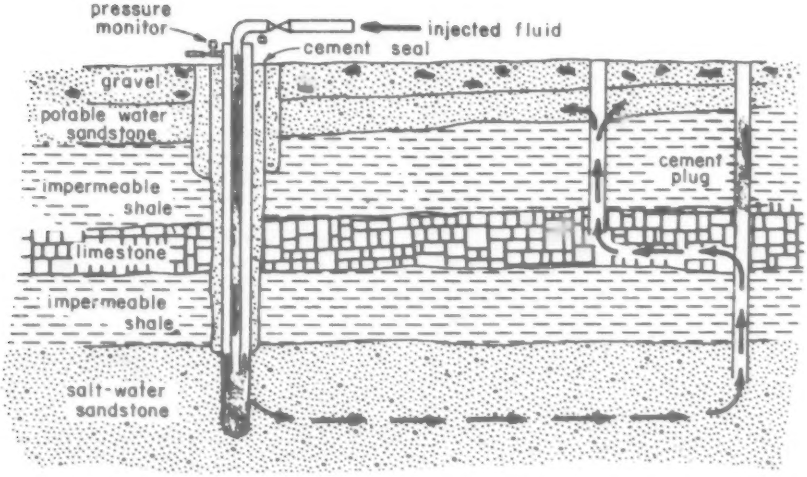
pressure monitor
injected fluid
cement seal
gravel
potable water sandstone
impermeable shale
cement plug
limestone
impermeable shale
salt-water sandstone

Figure 3.9 Escape of injected fluid through abandoned boreholes in area. (modified from U.S. EPA, 1977)

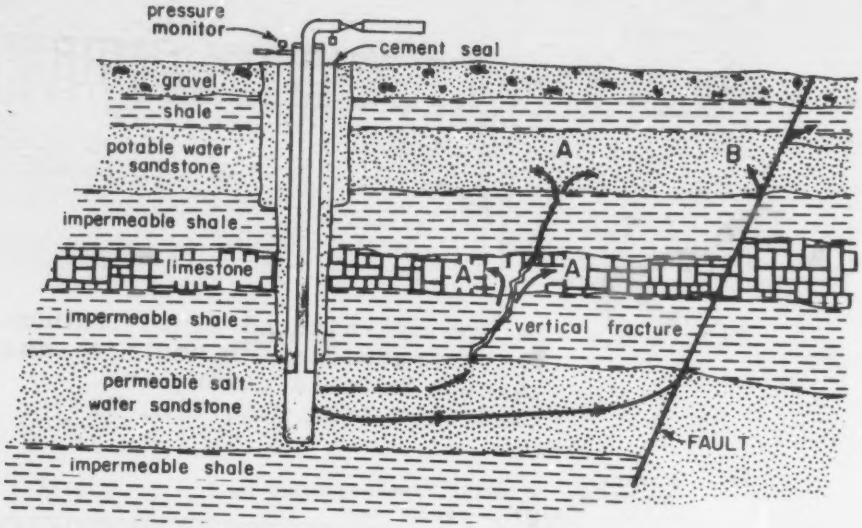
pressure monitor
cement seal
gravel
shale
potable water sandstone
A
B
impermeable shale
limestone
A
A
impermeable shale
vertical fracture
permeable salt-water sandstone
FAULT
impermeable shale

Figure 3.10 Escape of injected fluid through fractures (A) and faults (B). (modified from U.S. EPA, 1977)

prescribed well construction practices and the large vertical distances between the injection zones and usable aquifers, reduce the probability of contamination of usable aquifers. Evidence for this conclusion is the scarcity of reports of direct contamination from this type of source. (Tempo, 1973, pp. 2-9.) Rigorous planning and monitoring programs are necessary to maintain this record.

In the special case of injection of cold water into a hot dry rock formation for heat recovery, the resulting temperature gradient in the rock should be considered. The differential thermal stress fields created by the cold water may result in excessive fracturing. Research has been done on this problem by the Futures Group (1975).

Baseline geologic, hydrologic, and well data, as well as input from system models, should be evaluated to predict potential pollutant mechanisms and pathways. The most obvious areas that must be analyzed are the role each fault may play and the possibility of other wells intersecting the injection zone and providing a pathway for interaquifer leakage.

To evaluate the role of faults in an area with concealed fault traces, the investigators may need to conduct some surface geophysical surveys. An electrical resistivity survey was conducted in the Salton Sea field which located at least four previously unidentified faults and confirmed the locations of two others (Meidav, et al. 1976). It is hypothesized that these faults bound the geothermal reservoir.

Geophysical well logging can be used to evaluate the subsurface conditions of wells that may provide channels for interaquifer pollution. Descriptions of the logs to run for this purpose are presented in Section 4.

Unknown structural or stratigraphic pathways may be discovered by conducting tracer studies. A naturally occurring tracer is preferable since it would be in the system for a long period and therefore would reveal any pathways that may take a long time to show up. Lithium, a unique constituent of some geothermal fluids, may serve as an ideal natural tracer. A limitation of this approach is that it will only detect pathways occurring under natural pre-production conditions. Those that may be induced by production activity will only show up at that time.

The baseline water chemistry study will also provide information on potential pollutant pathways. In comparing the chemistry of geothermal water with other wells and springs, mixing relationships may be derived. Determination of where and how this mixing occurs will provide clues to where geothermal waters mixing with ground water may increase or decrease with production and injection.

Some questions to ask are:

- Do any ground water barriers show on the water level contour maps? (Do they coincide with mapped fault locations?)
- Does the construction of any used or abandoned well indicate that it may provide a potential pollutant pathway?
- Does the water chemistry data indicate anomalies, discontinuities or spatial trends?
- How will the superposition of the production and injection flow dynamics affect the confinement of the reservoir? How will it affect flow in overlying aquifers?
- Which faults are acting as conduits and which as barriers to ground water flow?
- Which geologic units will confine injected fluids and which will protect near surface aquifers?
- Are there any man-made subsurface structures or excavations such as mines or tunnels that may present a hazard?

3.2.3 Chemical Reactions in the Aquifer

The main chemical reactions that may be expected in the injection zone are those that cause formation plugging around the injection well. Silicates and carbonates cause most plugging in geothermal systems. Other reactions should be minimal since the composition of the injected fluid will be very similar to that of the resident fluid in the injection zone.

The zone of reaction around geothermal injection wells is probably similar to that around other types of industrial waste disposal wells. A gradational boundary (zone of reaction) develops between the injected and the formation fluids. In this zone, some minerals will be dissolved or altered, metastable sols and gels will form and new compounds will precipitate. The extent of this zone will depend upon the length of time the fluid has been injected and its flow rate, the mixing rate of the injected fluid and formation water, and chemical reaction rates. Although chemical reactions may be predicted by laboratory mixing of the two fluids, the physical effect on the system is difficult to predict. A precipitate, for example, may immediately plug the formation, may pass through without plugging it (especially if fracture permeability exists), or may slowly accumulate and retard injection. Formation plugging can also be caused by swelling clays due to formation water incompatibility. However, this problem is restricted to sedimentary reservoirs.

Bacterial growth, which causes plugging around some nongeothermal injection wells, should not be a problem in geothermal injection wells. Few bacteria thrive in such high temperatures.

If the fluid is not filtered prior to injection, particulate and colloidal matter may plug the formation.

3.2.4 Effects of Alternative Development Scenarios

This evaluation stresses the concept that there may be more than one way to approach each development situation. If the initial proposal looks like it may produce a hazardous condition in usable aquifers, then the components producing that situation should be altered. Situations that may develop are:

1) indications that the planned injection pressure or expected increased pressure to maintain the injection rate may hydrofracture the confining formations of the reservoir;

2) indication from modeling that the planned production and injection rates may have a deleterious effect on the reservoir or overlying formations, e.g., changes in formation pressure, subsidence, change in natural recharge to shallower used-aquifers, etc.;

3) the planned location of an injection well is near a hydraulically conductive fault;

4) indications that the temperature of the injected fluid may contribute to plugging of the injection zone;

5) geophysical well logs indicating that casing or cement completion is not adequate.

If any of these, or other potentially hazardous situations, are recognized, an alternative plan should be developed before fluid disposal begins.

3.3 DEFINE LIMITS OF DETECTION

The monitoring plan should be designed to detect chemical changes in the ground water. These changes should be perceived as occurring in a spatial and temporal matrix. The necessary chemical, spatial and temporal sensitivity of detection in the matrix must be specified for each area. The chemical sensitivity required is mainly a function of:

a. chemical contrast of geothermal and nongeothermal fluids;

b. environmental sensitivity to particular constituents;

c. natural variations in water characteristics; and

d. available analytic techniques.

The temporal and spatial sensitivity required is mainly a function of:

a. hydrologic factors;

b. the relative size of the development;

c. characteristics of potential pollutant pathways; and

d. water use and well distribution density in the area.

These parameters will be analyzed, based on pertinent regulations by EPA and other agencies, to help determine sampling frequency, distribution and density of sample points, significant chemical and physical parameters, and methods of sampling and analysis. Where ground water is used extensively, rapid detection of minute changes in quality would be more desirable whereas in areas where ground water is poor and not used, larger variations and less frequent sampling may be acceptable. Consideration of the required limits of detection will ensure that the monitoring plan is not over- or under-sensitive. The chemical, temporal and spatial sensitivity factors are discussed in detail below.

3.3.1 Chemical Detection Sensitivity

The chemical contrast of geothermal and nongeothermal fluids will be defined in terms of 1) the magnitude of the chemical difference between them, 2) identifiable characteristics of each, and 3) their degree of natural mixing in different parts of the study area. If the difference between the fluids is not significant, then no ground water degradation will occur. The monitoring program will then consist only of periodic sampling and analyses of production, injection and nongeothermal fluids to ensure their continuing integrity.

The two fluids may be similar if the quality of geothermal fluid is quite good or if nongeothermal ground water is of low quality. For example, in the vapor-dominated Matsukawa geothermal field, steam condensate has almost the same composition as that of water in a nearby river. In fact, this condensate has been used with no adverse effect to irrigate local rice paddies. On the other hand, some of the nongeothermal ground water in the central part of the Imperial Valley has salinity levels of over 15,000 ppm higher than some of the geothermal fluids produced in the area.

It would be desirable if either the geothermal or nongeothermal fluid had a unique chemical characteristic or "signature". This would be an element, compound or isotope that: 1) occurred only in one type of fluid in the area; and 2) remained identifiable throughout the chemical reactions of the fluid. An isotope study in Imperial Valley has been cited in Section 3.1.4. One possible "signature" could be an element such as lithium which occurs in Imperial Valley geothermal fluids and is quite rare in other ground waters. Lithium is especially appropriate for this purpose because soils apparently absorb it less than most other common ion exchange minerals.

The degree of natural mixing, if any, of the geothermal and nongeothermal ground water will influence the required limits of detection. It will be necessary to define the temporal variation or trends of natural mixing at each location. These variations or trends can be seasonal, cyclic, increasing, decreasing, increasing ratios or decreasing ratios. Increasing ratios of geothermal fluid to nongeothermal fluid may result from channels opening due to tectonic movements. Decreasing ratios may result from silicification of existing channels. It is believed that at Roosevelt Hot Springs, Utah, the thermal waters naturally leak westward from the springs into the Milford Valley cool ground water system (Parry, et al. 1976). Some researchers believe that production of the reservoir fluid may lower the hydrostatic head and inhibit leakage. This would decrease the ratio of geothermal to cool ground water and thereby improve the quality of the latter.

Baseline chemical changes of samples over time must also be considered in defining significant limits of detection. If such changes have occurred under natural conditions, then detection of them after development would probably be unrelated to the development. The variation would have to be greater in quantity or different in character than the naturally occurring difference to be considered significant. For example, the varying quality of agricultural, industrial or municipal wastewater would cause changes in ground water chemistry not attributable to geothermal development.

Although the procedures for sample collection, handling and analysis should always be rigorously followed, some situations may not require the most sensitive analytic techniques but may permit those which are faster or more economical. For example, in some situations where only a rough check on a water of known composition is necessary, a specific conductance measurement may suffice.

3.3.2 Temporal and Spatial Sensitivity

The main hydrologic factors of concern are ground water flow velocity and areal and depth distribution of aquifers. Generally, the frequency of sampling should be proportional to the fluid flow velocity. All other things being equal, the faster the fluid is traveling the more frequently samples should be taken. Unless tracer studies are conducted (see Section 3.4.5), flow velocity determination may be deceptive in most geothermal reservoirs with fracture porosity. In contrast to the more predictable flow in a homogeneous reservoir with intergranular permeability, the flow in a reservoir with fracture porosity may vary considerably from one location to another.

Certain areas will require greater detection sensitivity than others; these areas are near the injection well, the aquifer immediately overlying the confining strata of the reservoir, wells penetrating the injection zone, other deep wells, and water use areas. This greater sensitivity will require a denser array of sample points and more frequent sampling.

3.4 EVALUATE MONITORING TECHNIQUES

Ground water monitoring should take place at the disposal facility as well as in the surrounding area. All of the monitoring techniques, except surface geophysics, involve the use of wells. Techniques that may be used in the wells are fluid sampling and analysis, well logging, tracers, pressure, temperature and flow measurements, and other special or developmental techniques. Each of these techniques and each type of monitoring well must be evaluated for its applicability to each geothermal development. This section discusses the techniques, except for well logging, and types of monitoring wells. The application of well logging to ground water monitoring is discussed in Section 4.

3.4.1 Monitoring Wells

Four types of monitoring wells may be used. The first three listed have been defined by Warner (1975):

1) nondischarging wells constructed into the receiving aquifer;

2) nondischarging wells constructed into or just above the confining unit;

3) wells constructed above the confining unit; and

4) the injection well.

Geologic data will be derived in drilling any of these wells, but each has a distinct additional monitoring objective.

The nondischarging wells in the receiving aquifer can be used to monitor the migration of the degraded fluid front. In geothermal situations this migration can be monitored by using temperature measurements in place of or in addition to chemical analyses. The rate, location, and direction of the injected fluid front will also provide information for the reservoir engineers to confirm their computations on the travel time of this front from the injection well to the production well. The wells in the receiving aquifer can also be used to monitor pressure or to detect chemical changes in the injected fluid due to reactions with the reservoir rock matrix. Pressure monitoring may be useful in detecting leaks to nearby structural features, abandoned wells or breaches in the confining layer. In discussing nongeothermal injection wells, Warner (1975) believes that monitoring wells constructed in the receiving aquifer provide very little useful information that is important to regulation. He states further that they are costly and may provide a conduit for potential degradation of overlying aquifers.

Wells constructed in or just above the confining unit may detect leakage through the confining unit itself. These wells should be nondischarging. If they are pumped they may induce leakage that would not normally occur through the confining unit.

Wells constructed above the confining unit will detect leakage into the unit they penetrate. These wells may be discharging or nondischarging. A discharging well will represent fluid from the volume encompassed by its cone of depression while a nondischarging well will represent only fluid in the well bore.

When monitoring for the effects of geothermal injection, the injection well itself may also be used as a monitoring well. In monitoring programs for deep well injection, the injection well is often the only monitoring well. Monitoring a properly constructed injection well will provide information on the volume of the injected fluid; its chemical and physical properties; well head, annulus and bottom hole fluid pressures; and condition of surface and subsurface facilities. Injection well monitoring is discussed in more detail in Section 3.4.4.

Well Samples--

The fluid in an aquifer will vary in composition vertically and horizontally. A sample taken from a nonflowing well will represent only the fluid for a small portion of the aquifer. A sample taken from a pumped well is a mixture of fluid encompassing the cone of depression, and characterizes a much larger volume of the aquifer fluid. Thus, if representative samples of the aquifer fluid are desired, it is necessary to pump the well.

Knowledge of the well construction is also necessary to determine which part of which aquifer is tapped. This is critical in order to specifically identify which strata may be degraded.

Samples from some wells, especially nonflowing, shallow ones, may be affected by infiltration from surface water through a poor well seal. The resulting water sample may be of a better quality than is actually in the aquifer.

3.4.2 Fluid Sampling and Chemical Analysis

Fluid sampling and analysis is the common and in most cases the only technique used in ground water monitoring. When properly used, this technique provides the most direct and reliable evidence of chemical changes in the ground water. It will be used in all ground water monitoring plans in addition to any other techniques chosen to supplement it. An overview of water sampling, collection and preservation is presented in Section 3.1.1.

3.4.3 Well Logging

The potential applications of well logging to ground water monitoring for geothermal development was of particular interest to this study. Hence, this monitoring technique is treated in detail in Section 4.

3.4.4 Injection Well Monitoring Techniques

Injection well monitoring will be an extremely important component of a geothermal ground water monitoring plan; in most existing plans for deep well monitoring, it is the only method used. The techniques used and scope for this type of monitoring is different from that used for other monitoring wells. Injection well monitoring includes determination of:

1) volume of injected fluid;

2) chemical and physical properties of fluid;

3) well head and annulus fluid pressures; and

4) condition of surface and subsurface facilities.

The following discussion of these components is extracted primarily from Warner (1975).

The fluid flow rate, injection wellhead pressure and annulus fluid pressure in the injection well must be monitored continuously to provide the necessary data for reservoir management, well maintenance and pollution control. Chemistry of the injected fluid, annulus fluid and condition of subsurface facilities should also be checked regularly.

The volume of injected fluid is monitored for several reasons. First, it will enable computation of fluid flow distance in the injection zone. Second, it will aid in interpretation of well behavior. Third, a record of the total mass of fluid emplaced is required by regulatory agencies and to compute unit costs.

The chemical and physical properties of the injected fluid are monitored to ensure that the fluid remains within design specifications. These properties may be monitored periodically or continuously. Parameters that have been monitored continuously in hazardous waste disposal wells are: suspended solids, pH, specific conductance, temperature, density, dissolved oxygen and chlorine residual. In addition, periodic complete chemical analyses should be conducted. The periodic biological analyses practiced in other types of disposal wells are not necessary in the geothermal environment.

Wellhead fluid injection pressure is monitored to keep a continuous record of reservoir injectivity. Increasing pressure would indicate formation plugging. At all times pressures must be kept below the level that would cause hydrofracturing of the reservoir or confining formation, or that would damage the well facilities. In addition, regulations require this pressure record.

The injection well is designed and constructed according to rigorous specifications, which are outlined in Section 3.5.4. In addition to other features, these specifications require a sealed fluid-filled annulus. The pressure and chemistry of the annular fluid are monitored to detect leakage in the system. Depending on the composition of the fluid, adequate chemical monitoring may be accomplished by placing conductivity probes in the annulus, or by analyzing return flow for contamination in continuous cycling annulus fluid.

Corrosion rate can be determined by placing sample strips of the tubing and casing material in the well, and checking them periodically for weight loss.

When injecting chemically active fluid, it is important that the well be shut down periodically for inspection and testing. Inspection methods for casing, tubing, cement and well bore include: (1) pulling the tubing and inspecting it visually or instrumentally; (2) electromagnetic caliper or televiewer logging of tubing or casing in the hole; (3) pressure testing of casing; (4) bond logging of casing cement; and (5) inspection of casing cement or well bore with injectivity or temperature profiles (Warner, 1975).

3.4.5 Other Monitoring Techniques

Other monitoring techniques that may be used in ground water monitoring include surface geophysics, tracers and electromagnetic probes. These techniques would generally be used as auxiliary methods for special situations. The principles behind these methods and their application are briefly described below.

Surface Geophysics--

Surface geophysical methods can supply information on subsurface structure and ground water flow patterns of hydrologic systems. These methods have been used successfully to delineate geothermal reservoirs and ground water conduits, such as faults, fractures or buried stream channels. Electrical techniques are used primarily, but seismic, gravimetric and magnetic methods can also supply information.

Electric methods--Electric methods have been used to detect shallow zones of saline and/or thermal water pollution, which can result from surface spills during well production or leakage from geothermal holding ponds.

The direct current resistivity methods utilize a direct or low frequency current introduced into the ground through a pair of metal electrodes. The resulting potential difference between the electrodes is a function of the resistivity of the subsurface rocks and fluids. The resistivity is, in turn, a function of the degree of subsurface fluid saturation and salinity, rock porosity, tortuosity of pore spaces, and temperature. The depth of observation is determined by the electrode spacing. Many different electrode configurations, or arrays, are commonly used. Resistivity surveys have been used successfully to determine the location of subsurface fluid conduits, the location of impervious strata, and the location of brine-fresh water interfaces. In areas where surface pollution from geothermal effluents is suspected, a resistivity survey could be used to map the extent of the pollutant mass.

Spontaneous potential and streaming potential methods involve the measurement of naturally occurring electric potentials developed locally in the crust by electrochemical and/or electrofiltration activity. The potential generated by water moving through a porous medium, or streaming potential is of special interest to hydrologic problems. Like resistivity surveys, measurement of this potential has been used to delineate rock and fluids of varying resistivity to locate leakage from reservoirs.

Electromagnetic or induction methods use a time-varying magnetic field as an energy source. This generally high-frequency magnetic field induces eddy currents in the presence of conductive materials which in turn create their own magnetic fields. The resultant magnetic field is measured in terms of the voltage induced in the receiver. Electromagnetic soundings can be made on the ground or from a low flying aircraft. In general, these methods lack the resolution and depth of penetration of direct-current resistivity; however, they are a more rapid and less expensive reconnaissance method. Electromagnetic probing is widely used in mineral exploration but has been little used in hydrologic surveys. However, they have been used effectively to map buried stream channels where the channel filling material has a significant resistivity contrast with the surrounding rock (Collett, 1967).

The induced polarization method relies on measuring the decaying time of artificially induced electric potentials. The origin of the induced electric polarization is complex and not well understood, primarily because it is the result of several physiochemical conditions (Zodhy, et al. 1974). This method is useful in identifying stratigraphy in some areas where continuity of layers is poorly defined by resistivity.

Other surface geophysical methods--Other surface geophysical methods have limited uses in defining subsurface hydrologic conditions useful for monitoring plans. The seismic refraction method is commonly used to determine the thickness of saturated sediments, depth to water and identification of buried stream channels. Gravity surveys supply a rapid and inexpensive means of determining the gross configuration of aquifers, if there is an adequate density contrast between the aquifer and the underlying bedrock. Magnetic surveys have been applied with limited success to the study of magnetic aquifers, mainly basalt, and to the configuration of basement rocks underlying water-bearing sediments. Theory and applications of these methods are discussed in detail by Zohdy, et al. (1974).

Tracers--

A tracer is a substance that is introduced at a known location in a water flow system. The goal is to define flow paths and parameters by detecting the tracer downgradient. Radioactive, chemical and dye tracers have been successfully applied to ground water investigations to determine ground water flow paths, aquifer parameters, and the vertical and horizontal movement of water within a borehole. The use of fluorescent dyes has not been widespread in ground water monitoring programs. Radioactive tracers offer the advantages of being detectable in small quantities, of having short half-lives and, when handled properly, of having relatively little adverse environmental effects compared to some chemical tracers (Smith, 1976).

The most widely used tracer in ground water studies is tritium, a naturally occurring isotope of hydrogen, with nuclear mass of 3. It is incorporated into the water molecule to form tritiated water (HTO) and in this form can follow the natural water flow. This unique feature makes it an extremely good tracer for ground water monitoring investigations. The disadvantages of tritium are that it requires sophisticated apparatus for detection and concentration levels cannot be measured in the field.

Tritium tracers have been used to monitor flow paths and effects of injected steam condensate at The Geysers (Gulati, et al. 1978). In this study, tritium was used primarily to determine the effect of injection on producing wells and reservoir characteristics.

This tracer has also been used to define geothermal reservoir properties. Vetter (1977) describes tracing tritium from injection wells to determine regional flow patterns within the reservoir, delineate fractures (their number, orientation and conductivity), detect permeable zones within the reservoir and leakage across impermeable layers or behind well casings.

High-Frequency Electromagnetic Probes--

Theoretical and experimental studies have been conducted using high-frequency electromagnetic probing for ground water monitoring (Lytle, et al., 1976). When injected and resident fluids have dissimilar electrical properties, a three-dimensional fluid flow profile can be determined. In this method, a transmitter is placed in the injection well and receivers are placed in nearby observation wells. The time variation of the attenuation and phase shift of the signal between the transmitter and receivers is monitored (Fig. 3.11). For a constant transmitting power, the receiver signals vary as the fluid progresses. The change in the signal is dependent on the percentage of the region the injected fluid occupies between the transmitter and receivers.

Instrumentation required for this method is currently very expensive, and interpretation techniques are still experimental.

3.5 DESIGN MONITORING PLAN AND ALTERNATIVES

Design of the monitoring plan is the culmination of all the data collection and synthesis to this point. The goal of the plan is to have the capability of detecting chemical changes in ground water characteristics within the specified chemical, temporal and spatial limits of detection. To efficiently achieve this capability the monitoring plan must not be constant or static. Some areas will require more frequent sampling, others will require a denser array of sampling points and still others will require different analyses. As the plan is carried out the actual needs of the area will become clearer and the plan can be adjusted for more judicious and efficient monitoring.

The components to be evaluated in arriving at an adequate monitoring plan are:

1) spatial distribution of sample points and sampling frequency;

2) applicable monitoring techniques;

3) chemical and physical parameters;

4) regulatory specifications; and

5) cost versus confidence.

These aspects are discussed below.

3.5.1 Spatial Distribution of Sample Points and Sampling Frequency

One of the most critical determinations in designing the monitoring plan is the adequacy of the spatial distribution (area and depth) of sample points. These points include monitoring wells, surface water sampling locations, hot or cold springs and geothermal manifestations. One method for determining an adequate

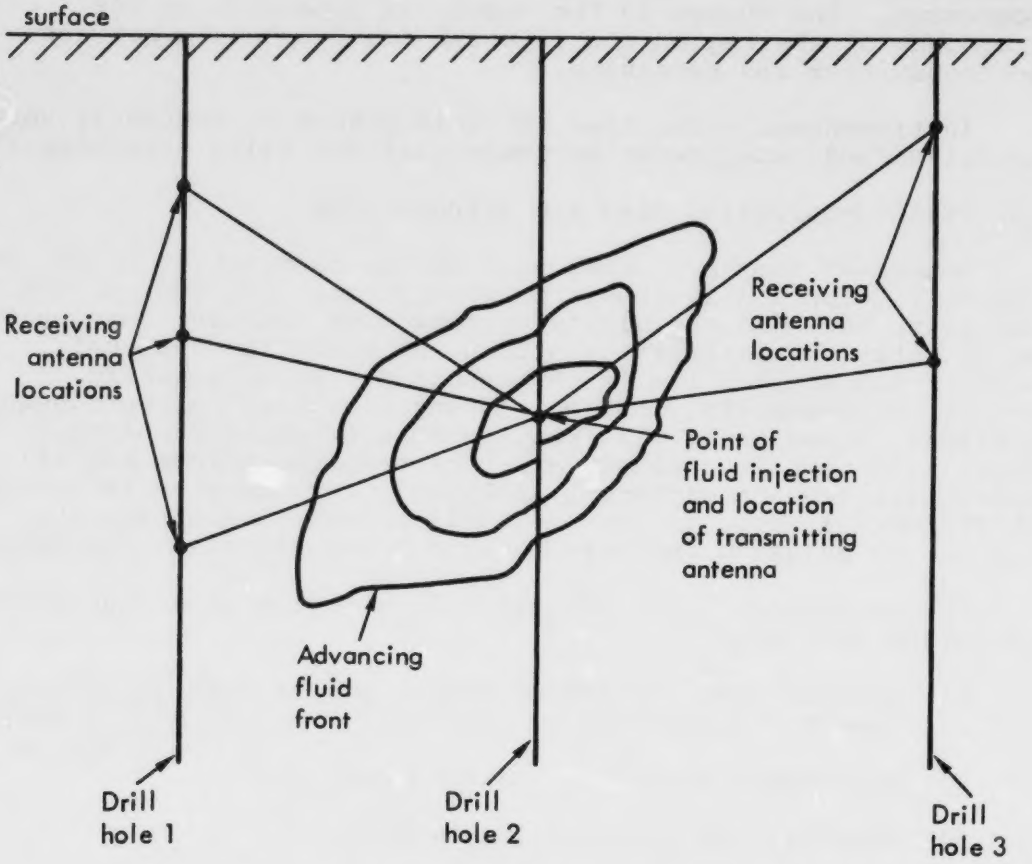
surface
Receiving antenna locations
Receiving antenna locations
Point of fluid injection and location of transmitting antenna
Advancing fluid front
Drill hole 1
Drill hole 2
Drill hole 3

Figure 3.11 Location of injected fluid front by high-frequency electromagnetic probes. (Lytle, et al. 1976)

spatial distribution of sample points is outlined below. Other investigators may have different approaches; each must be evaluated in its application at a specific site.

The choice of potential monitoring sites involves several steps:

1) plot the areal extent of each aquifer unit on a separate map;

2) plot the locations of potential degradation sources or pathways for each aquifer penetrated, including injection and production wells and wells of known or suspected deteriorated condition;

3) plot existing wells with potential for monitoring in each of these units;

4) plot the locations of all other wells in use or in potentially usable aquifers; and

5) if possible, estimate the radius of the cones of depression for each discharging well.

In all cases the usable or potentially usable aquifers will lie above the geothermal production and injection zone. Ideally, there should be a monitoring well in each unit above this zone, and near and somewhat downgradient from each potential pollutant source well or structural pathway. This would enable detection of possible leaks through each of these mechanisms.

Ideally, monitoring wells should also be located on the vectors between the injection well and each discharging well area. These monitoring wells should be as close to the injection well as practical.

The type of monitoring well distribution outlined above would provide a considerable degree of detective protection. It would cover each foreseeable pollutant pathway. Areas that have a sufficient distribution of existing wells to use for monitoring in such a pattern are rare. All existing wells suitable for monitoring in such locations should be incorporated into the monitoring plan.

Providing this extensive degree of protection in most areas would require the effort and expense of drilling many monitoring wells. However, adequate protection may also be derived with a system that is not quite as encompassing. Geologic, hydrologic or well log evidence may all but rule out leakage through some of the potential degradation pathways. For example, if well logs indicate that the casing and cement in a well is completely intact, then it would be unlikely to act as a conduit for interaquifer flow, and drilling a monitoring well nearby would be unnecessary.

If there are monitoring wells on each vector between the injection and discharging well areas, one well near the injection well may be close to several vector paths and hence could satisfy the criteria for monitoring each flow path.

In deciding on locations for monitoring wells, the hydraulic conductivity and gradient of each aquifer must be considered. Areas of higher conductivity within an aquifer should be specified with priority given to monitoring such locations, especially those that occur between the injection well and well discharge areas.

To monitor the advance of the degraded fluid front in the receiving aquifer, nondischarging observation wells may be constructed in appropriate locations. These wells will provide information to verify or modify the predictions of degraded fluid advance and perhaps reservoir performance.

Sampling Frequency for Monitoring Wells--

Initial sampling frequency for a monitoring plan is based on experience with plans in similar localities. It will be modified by successive approximations to the optimum frequency for each well in the area. The sampling will be more frequent and somewhat conservative until sufficient data have been collected to justify less frequent sampling. There are several relationships that should be considered in determining sample frequency for a site-specific monitoring plan. All other things being equal, sampling frequency would be greater

1) in an aquifer that has high fluid velocity than in one with low fluid velocity;

2) closer to and downgradient from potential pollutant sources, such as injection wells, structural pathways; etc.

3) in the injection well.

Because of the much slower flow of ground water, its chemistry fluctuates much more gradually than that of surface water. Under natural conditions, deeper ground water will generally flow more slowly than shallower ground water and fluctuations in their chemistry will be proportional. Superposition of geothermal production and injection in a deep aquifer will change this natural relationship. An estimate of an initial sampling frequency can be obtained by computing the time it would take for the fluid to flow from an injection well to a nearby monitoring well. The sample frequency can be specified as a fraction of this travel time.

Until the properties of the chemical changes and fluid flow are known for each aquifer, the initial sample intervals would generally be specified for one to several days, weeks or months, depending on the monitoring locations. For example, a monitoring well very close to and downgradient from the injection well in the same aquifer or one immediately adjacent could be sampled hourly or daily from the start of injection. As data are collected to show that the system is behaving as predicted, the intervals can be increased. They can be reduced or extended as the monitoring program proceeds and the flow properties are better defined. The same interval adjustments need not apply to all the wells. In fact, some wells might need more frequent sampling. Generally, the monitoring plan would not specify sample intervals greater than one year for most locations.

3.5.2 Applicable Monitoring Techniques

The techniques chosen for the monitoring plan will most likely be a combination of chemical sampling and analysis, well logging and injection well monitoring. Other techniques will be used only in special circumstances.

The importance of chemical sampling and analysis (discussed in Section 3.1.1) is essential to any fluid quality monitoring plan. In most cases it would provide the mainstay of the detective monitoring plan.

Well logs would not be absolutely necessary but, as outlined in Section 4, would provide information that would greatly add to the reliability, accuracy and confidence of the plan. Extremely important applications that should be included are:

1) continuing surveys to detect leakage from injection and production wells; and

2) periodic surveys to detect leaks from other wells penetrating the injection zone, or that may provide conduits for interaquifer leakage.

The detailed vertical profiles of rock and fluid properties provided by well logs would greatly enhance any monitoring plan and should be used at least in the baseline data acquisition phase.

Injection well monitoring will be an essential component of any monitoring plan. This component is discussed in Section 3.4.4.

Tracers may be used in situations where it is desirable to detect suspected pollutant pathways in certain areas. Surface geophysical techniques may be used to detect the extent of infiltration of a surface spill, or the location of a shallow buried stream channel deposit.

3.5.3 Chemical and Physical Parameters

Standard chemical analyses should initially be recommended for all sample points. These should include determination of:

silica
calcium
magnesium
sodium
potassium
carbonate and bicarbonate
sulfate
chloride
nitrate
fluoride
total dissolved solids
pH
gross radioactivity
temperature

The Geothermal Environmental Advisory Panel (GEAP, 1977) adds dissolved oxygen and total phosphorus to this list. Constituents that have local significance should also be added.

Some monitoring wells may have fluids entirely or partly of geothermal or suspected geothermal origin. Analysis of fluids from these wells may be conducted for the constituents listed in the GEAP Guidelines as follows:

a. all parameters specified for ground water

b. gases: CO_2, H_2S, SO_2, NH_3 and Rn-222

c. aqueous species: As, Ag, B, Ba, Cd, Cr, Cu, Fe, Hg, Mn, Mo, NH_4, Pb, Se, Sr and Zn

However, the gases and aqueous species they list for analysis do not include all the components of geothermal fluids. Other aqueous species that have been found in significant quantities (maximum reported concentration greater than 100 mg/l) are aluminum, bromide, iodine, lithium and rubidium. Most other elements have also been found in minute quantities in some geothermal fluids (Tsai, et al. 1978).

To determine which elements occur in a particular geothermal fluid, some type of comprehensive spectrographic analysis may be performed at least in the beginning of the study (e.g. neutron activation, spark source mass spectrometry). This will provide a survey of what elements are present. Certain elements that are not detectable in these types of analyses may be accounted for with other analytic techniques. This complete analysis should determine the complete suite of trace elements in the fluid. Those that may involve: (1) significant potential environmental effects; (2) chemical reactions in the geothermal system; or (3) diagnostic tracer species may be specified for continued monitoring.

Chemical analyses for the produced and injected fluid are similar to those described for geothermal monitoring wells. Additional physical measurements of fluid volume, pressure, temperature and well conditions would be measured for the injection well, as described in Section 3.4.4 on injection well monitoring techniques.

Complete or standard chemical analyses may not be required at each sample interval. Where the specific conductance measured in the field does not vary by more than 10% from the initial measurements, further analysis may be omitted.

Physical parameters to monitor are:

water level
temperature
specific conductance
well discharge volume and rate
well condition

The water level measurements will provide important information on possible changes in hydraulic head, hence changes in flow rate and direction, that may be caused by geothermal production and injection. Significant changes in well discharge data may have a similar effect. The temperature may provide information on increasing or decreasing contributions from geothermal sources. The specific conductance is directly proportional to the salinity of the fluid and changes in it indicate changes in the fluid chemistry.

3.5.4 Regulatory Specifications

Federal and state regulations will require certain features in injection well planning, construction and monitoring. The

Safe Drinking Water Act (SDWA) of 1974 gives the EPA authority to protect ground water by regulating waste disposal wells and to protect aquifers designated by the EPA as "sole sources" of drinking water. It is the main Federal law regulating subsurface disposal. It contains guidelines for permission and operation of waste injection wells. The states adopt programs, subject to EPA approval, which will require permits for the underground injection of wastes. Currently, the EPA has a position statement (Administrator's Decision Statement No. 5, Appendix A) including planning and monitoring requirements. The USGS has issued Geothermal Resources Operational Orders (GRO's) and guidelines for acquiring environmental baseline data on Federal geothermal leases (GEAP, 1977). As of 1974, several states that allow injection also had explicit or implicit monitoring requirements (Reeder, et al. 1977, pp. 1 and 157). Most state regulation of disposal wells would be administered by the State Engineer. Specific monitoring regulations that may be required by a state must be included in the overall monitoring plan. Many of these regulations also include specifications for preventive measures in injection well design and construction, and surface facilities for containment of accidental spills.

The EPA statement has detailed data acquisition requirements for evaluation of the injection plan. This includes evaluation of the geology, hydrology, chemistry, injection interval, volume, rate and chemistry, bounding beds, well engineering data. The portion relating to monitoring specifies, "plans for monitoring including a multipoint fluid pressure monitoring system constructed to monitor pressures above as well as within the injection zones; description of annular fluid; and plans for maintaining a complete operational history of the well".

Safe Drinking Water Act--

Proposed regulations under the SDWA would govern State Underground Injection Control Programs (SUICP's). Such programs are intended to protect underground drinking water sources from contamination by injected effluents. Subpart C of the SDWA, "Protection of Underground Sources of Drinking Water," deals with injection wells and requirements include the following:

1) all existing injection operations are reviewed, and those which appear to endanger drinking water sources are suspended for investigation;

2) proposed injection wells which intersect aquifers with TDS less than 3,000 mg/l must use a double-pipe design (injection tubing inside a casing) and a packer preventing effluent from entering the annulus;

3) all existing and proposed injection sites must obtain an underground injection control permit, the requirements of which are outlined in this program;

4) public notice of permit applications must be given, with provisions for a public hearing; and

5) a specified monitoring program and reporting procedure must be followed

The applicability of these requirements to geothermal wells has not yet been established.

The EPA August 31, 1976, draft of the SUICP is presently being revised due to intense public pressure. Options to the initially proposed SUICP that have been proposed include:

1) Section 1421(b)(2) of the SDWA prohibits state programs from interfering with or impeding injection connected with secondary or tertiary recovery of oil or natural gas, unless underground drinking water will be endangered by such injection. It has been proposed that the geothermal industry be treated similarly to the oil and gas industries.

2) Proposed regulations would be applied to industrial waste injection, but less stringent controls would be placed on "resource recovery wells" (the name under which the proponents categorize geothermal and petroleum industry brine injection wells).

3) Non-retroactivity of proposed regulations.

4) Existing wells that are used only for brine disposal be granted special permits or eliminated within 10 years.

USGS Regulations--

GRO's are issued under the Geothermal Steam Act of 1970. Pollution, waste disposal and water quality are discussed in GRO Order No. 4 which covers general environmental protection requirements.

GRO Order No. 4 states that harmful liquid effluent must be disposed of in a manner conforming to Federal, state and regional standards or be injected into the geothermal reservoir or other formation approved by the Area Geothermal Supervisor.

A plan of injection, injection reports, inspection criteria, well drilling and conversion specifications is required. The primary responsibility for water quality is delegated to states with EPA approved standards.

Under GRO Order No. 5, a development operation plan is required to include:

1) a proposed well spacing map;

2) geologic and geophysical map;

3) representative drilling program;

4) proposed utilization of geothermal resource;

5) surface equipment installations; and the

6) proposed liquid disposal program.

The plan of injection is required to include:

1) a map of wells and facilities;

2) injection fluid characteristics;

3) proposed disposal zone characteristics;

4) subsurface maps and cross sections;

5) logs and histories of disposal wells;

6) representative injection well drilling program;

7) proposed downhole and surface equipment;

8) proposed injectivity surveys and monitoring; and

9) the hydrology of the area.

The GEAP guidelines recommendations apply to baseline data collection. Those relating to ground water include specifications for:

1) chemical analysis standards;

2) sources to be sampled, including surface and ground water and geothermal fluid;

3) frequency and duration of sampling for surface, ground and geothermal waters;

4) physical parameters to be measured including discharge, temperature, pH, specific conductance and turbidity; and

5) chemical parameters to be measured.

3.5.5 Cost Versus Confidence

Assuming competent planning and execution of a monitoring plan there is a direct relationship between the cost of the plan and the degree of confidence obtained. This relationship is generally perceived as exponential, and beyond a certain point returns diminish per unit increase in cost. Although this point is rather subjective, it is hoped that a viable monitoring plan can be achieved before this point of diminishing returns is reached. To do that the degree of confidence desired must be reconciled with the amount of money to be spent. In most cases the study outlined in this methodology will allow this reconciliation. Monitoring plan costs consist of costs for:

1. baseline study;
2. monitoring planning;
3. construction of new wells or modification of existing ones;
4. sampling frequency;
5. chemical analyses of samples;
6. monitoring techniques used; and
7. data synthesis and interpretation.

The first two items are one-time costs, the third may be one-time or periodic, the last four are continuing. If the first two components are considered to be relatively fixed by regulatory constraints, precedents or environmental concerns, components 3 through 7 are more discretionary. These aspects are discussed below.

Spatial Distribution--

Proper understanding of the geologic, hydrologic, well and reservoir conditions will allow confident determination of probable flow paths. A few strategically located monitoring wells can function more effectively than many arbitrarily placed wells. If possible, existing wells should be used as monitoring wells. The well placement should be designed in a progressive way. That is, a few wells could be constructed first in critical areas, e.g. close to and directly downgradient from injection wells in each aquifer. These would be placed to ensure detection of any escaping fluid from these sources. In this type of plan, it is imperative that the first line critical coverage be comprehensive. Additional wells would have to be constructed if and when degraded fluid is detected in these first line warning wells. Appropriate preventive measures would be taken at the source of the leak and a second line of wells should be constructed only in the affected aquifer. This type of approach may be the most efficient since wells are only placed in areas that have been shown to be suspect. It would provide a good degree of confidence without the initial cost of an extensive and widespread monitoring network.

Initially the only wells that may be conduits for interaquifer pollution due to injection would be those that penetrate the injection zone. In most areas only geothermal wells would be in this category. Any wells which penetrate the injection zone and are suspected of allowing vertical flow should be checked with the well logs described in Section 4. If significant quantities of fluid are escaping or could escape under production and injection conditions, the well should be repaired or plugged.

Any new wells should be designed to provide maximum safety for potential pollution. Casing material should be chosen with consideration of conducting well log surveys in the hole (i.e., perhaps case with fiberglass).

Sample Frequency--

Sampling frequency must be determined for each case. The data must be evaluated as it is collected. Appropriate modifications outlined in Section 3.5.1 may then be made.

Chemical Analyses--

One way to reduce chemical analysis costs for the monitoring wells is to analyze fewer parameters. Rigorous determination of the parameters that are necessary for monitoring at a specific site might reveal some constituents that may be safely deleted from the original list. Another approach would use the field-specific conductance determination after the initial complete analyses have been conducted. If this measurement is within specified limits of the initial measurement, then another complete chemical analysis would not be necessary. This may maintain an acceptable degree of confidence in the water quality monitoring and significantly reduce the operating costs.

Other Monitoring Techniques--

Well logging and injection well measurements will probably be the only other monitoring techniques used. Since well logging is quite costly, it must be used judiciously. These costs are outlined in Section 4.3.5.

Injection well measurements are necessary and fairly well defined, so there are no significant cost savings considerations.

Costs of other monitoring techniques are site and sensitivity dependent. It would be necessary to evaluate each of these independently.

Data Synthesis and Interpretation--

One way to reduce the cost of data synthesis and interpretation is by automation. A computerized information storage, retrieval, mapping, interpretation and data management system could be set up. Since computer systems are more economical with repeated applications it would be advantageous to have one system that all geothermal developers could use. The system could be devised to allow application to all ground and perhaps even surface water monitoring systems. Such a general application would distribute the development cost over a larger body of potential users and thereby reduce the unit cost. Development of such a data system is discussed further in Section 5.

3.6 IMPLEMENT MONITORING PLAN

Implementation of the monitoring plan will consist of three parts:

1) data collection and analysis;

2) data synthesis, display and interpretation;

3) review and modification of monitoring plan.

3.6.1 Data Collection

The data collection will be conducted at the specified frequency and locations. In most cases a well logging company will be contracted to run the well logs. The fluid sampling and analyses should be conducted according to the procedures specified in the baseline data acquisition and monitoring plan design phases of the monitoring methodology. Some phases of injection well monitoring should be continuous and others should be periodic.

3.6.2 Data Synthesis, Display and Interpretation

Data will be acquired regularly, according to the monitoring plan, for fluid chemistry, well logging and injection well monitoring. Previous data should be reviewed and correlated with the new data. Synthesis of fluid chemistry data is discussed below. Well logs are discussed in Section 4. The results of injection well monitoring may require the attention of a reservoir engineer.

Several graphical techniques for water chemistry data synthesis are described by Hem (1970). The Stiff diagrams which are described by Hem (1970) may have to be modified for application to geothermal situations. In geothermal areas where the TDS of the fluid varies by more than one order of magnitude, percent reactance may be used instead of milliequivalents per liter for the horizontal scale (Geonomics, 1978a). Although this will eliminate the graphic depiction of concentration, it will maintain the consistent symbol shape representing similar proportions of constituents.

Langelier-Ludwig Diagrams--

The Langelier-Ludwig (L-L) diagram (Langelier and Ludwig, 1942) (Figs. 3.12, 3.4 and 3.5) is similar to the rhombohedral section of the Piper diagram (Piper, 1944). It is a square plot of percent reactance of alkalic cations (Na+K) ascending from 0 to 100 on the left hand vertical axis and hardness cations (Ca+Mg) descending from 100 to 0 on the right hand vertical axis. The horizontal axes plot percent reactance of carbonate anions (HCO_3+CO_3) and noncarbonate anions (SO_4+Cl), with each axis reciprocating the scale of the opposite axis. This diagram provides a method for "segregating analytic data for critical study with respect to sources of the dissolved constituents in waters, modifications in the character of water as it passes through an area and related geochemical problems" (Piper, 1944). It allows for investigation of compositional relations among samples and statistical populations of samples in the form of clusters of points.

Salinity sections (Figs. 3.12 and 3.5) can be drawn at any orientation on the Langelier-Ludwig diagram to depict changes in concentration. These sections are constructed by projecting all the data points to be included in the section onto a straight line extending from one L-L diagram axis to an opposite axis. A triangle is formed by extending two lines from above at an angle of about 90° to intersect the ends of the L-L diagram section line. This section can be visualized as one side of a four-sided pyramid with the L-L diagram as the base. The apex of the pyramid would represent zero salinity. Lines of constant chemical constituent ratio and decreasing salinity would connect

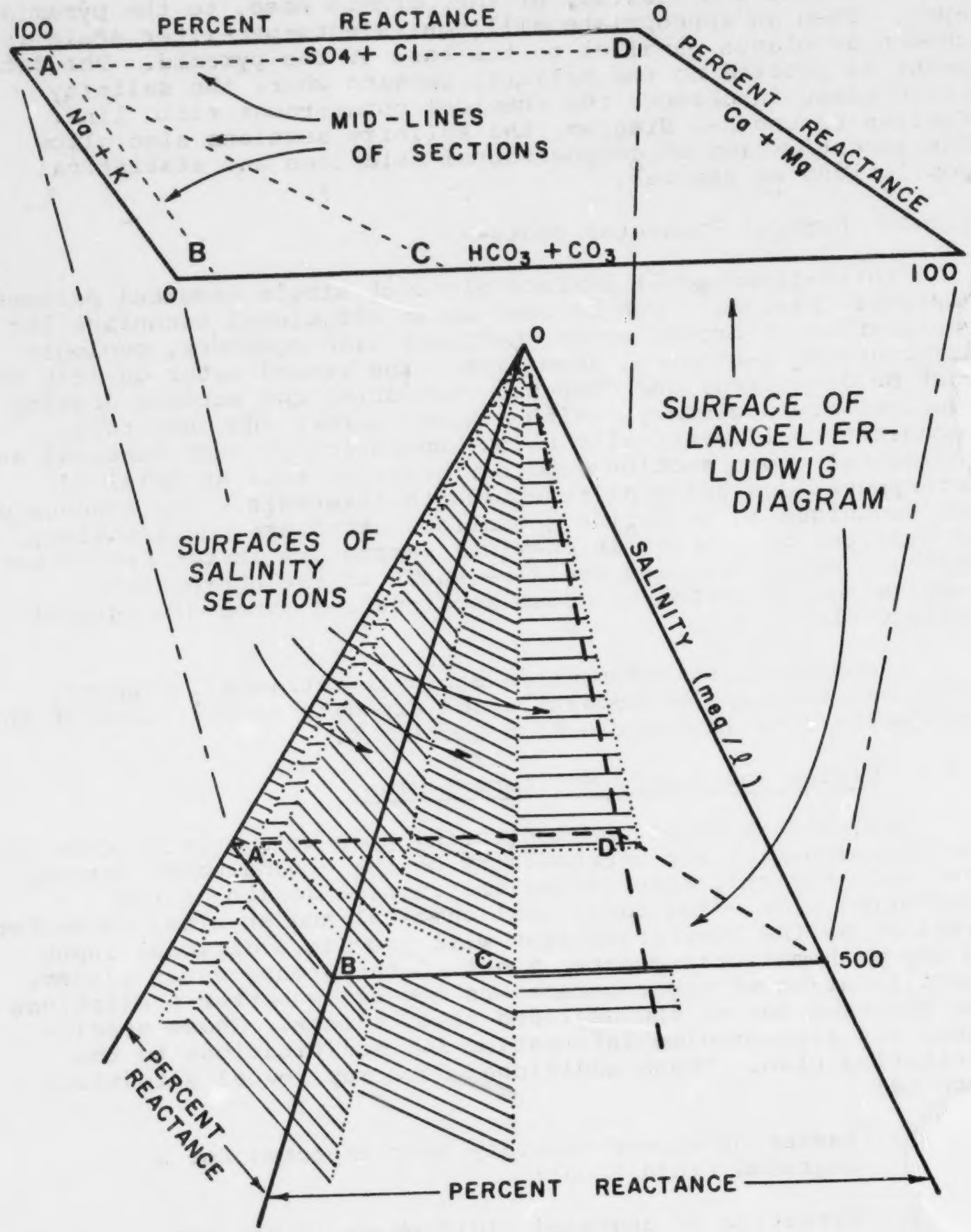
100
PERCENT REACTANCE
0
A
SO4 + Cl
D
PERCENT REACTANCE
Ca + Mg
Na + K
MID-LINES OF SECTIONS
B
C
HCO3 + CO3
0
100
0
SURFACE OF LANGELIER-LUDWIG DIAGRAM
SURFACES OF SALINITY SECTIONS
SALINITY (meq / ℓ)
A
D
B
C
500
PERCENT REACTANCE
PERCENT REACTANCE

Figure 3.12 Three-dimensional perspective of a Langelier-Ludwig diagram showing surfaces of salinity sections. (Geonomics, 1978a)

points on the L-L diagram, at the pyramid base, to the pyramid's apex. Then an appropriate milliequivalents-per-liter scale is chosen as planes parallel to the base of the pyramid. The data point is plotted on the salinity section where the salinity value plane intersects the chemical constituent ratio line. Similar to the L-L diagram, the salinity sections also allow for investigation of compositional relations and statistical populations of samples.

Single Chemical Parameter Plots--

Three-dimensional surface plots of single chemical parameter contours (Fig. 3.3) can be used as an additional technique for correlation of ground water chemistry with aquifers, geologic structure or geothermal anomalies. The ground water quality data must be digitized, and computer contouring and surface drawing routines are necessary. With minimal effort and cost this technique could eventually allow generation of many vertical and horizontal cross sections and surfaces, as well as trial interpretations using different depth intervals. The essence of the technique is to define subsurface structure and lithology as depicted by changes in chemical parameters in the ground water system. These features could be shown in the appropriate combination of contoured cross sections and three-dimensional surface plots.

A computerized information storage, retrieval, mapping, interpretation system to handle and expedite assimilation of the monitoring data is described in Section 5.

3.6.3 Review and Modify Monitoring Plan

Implementation of the monitoring plan will provide data on the hydrodynamics and geochemistry of the ground water systems that were not available during the initial design of the monitoring plan. The additional chemical and physical parameters provided by the monitoring plan will provide additional input to any mathematical/computer model of the ground water system. Quantification of these parameters may allow better predictions for the behavior of the degraded fluid fronts. These predictions may also provide information for modifications to the monitoring plan. These additional data may reveal situations such as:

1) faster or slower velocity than expected for a degraded fluid front;

2) detection of degraded fluid where it was not anticipated;

3) indications of unanticipated advance in a particular direction or strata;

4) detection of unanticipated chemical changes or constituents; and

5) detection of structural, stratigraphic or well-bore pollutant pathways, etc.

Evaluation of these data will lead to necessary and/or beneficial modifications to the plan. This evaluation will utilize considerations similar to those incorporated in the initial design of the plan. Modification may include:

1) adding or deleting sample points;

2) increasing or decreasing sampling frequency at particular sample locations;

3) adding or deleting certain chemical analyses at particular locations;

4) specifying different analytic methods;

5) changing sample collection procedures;

6) changing data synthesis and interpretation procedures; and

7) changing review and modification procedures.

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SECTION 4

APPLICATION OF WELL LOGGING TO GROUND WATER MONITORING IN GEOTHERMAL AREAS

The application of well logging to ground water monitoring in geothermal areas is described in this section. Subsurface data collection, well logging tools, log interpretation philosophies in geothermal environments, and logging costs are discussed. Well logs can aid in defining the baseline conditions of a subsurface hydrologic regime by supplying data on aquifers, regional ground water flow paths, water quality and the relationship of wastewater injection zones to nearby fresh ground water systems. Well logs can also detect leakage from injection and production wells and aid in monitoring water quality throughout the monitoring network.

4.1 SUBSURFACE DATA COLLECTION

To design a ground water monitoring program, the geohydrologic conditions in an area must be defined. The subsurface data necessary to define these conditions can be collected directly from drill holes by sampling fluids and rock, by flow tests, and by well logging. Each of these techniques will evaluate different aspects of rock and fluid properties. For example, rock cores provide the best and most direct lithologic and mineralogic determinations, as well as some clues to in situ permeability. On the other hand, flow tests provide the best data for in situ permeability and only very indirect evidence about rock types. Data on water quality can be gained from complete chemical analyses on fluid samples from a drill hole.

Well logs, with proper interpretation, can provide much information on rock and fluid properties such as lithology, porosity, permeability, density, relative water quality, fluid movement and borehole temperature. However, logging cannot entirely replace sampling. For correct interpretation, some samples, properly taken and analyzed, are essential to the interpretation of logs in each new geologic environment. Data collected by well logging must always be correlated to the nearest wells where core or sampling data are available, and one well, adequately sampled and logged, can serve as a guide for other wells in the same terrane.

Under ideal conditions, correctly interpreted well logs can provide continuous and detailed vertical profiles of rock and water properties at an acceptable cost. The subsurface volume explored by logs can be up to 100 times that investigated by rock or fluid sampling in the well bore (Keys and MacCary, 1971). Logs also provide data collection capabilities in cased holes. Applications of well logs in water quality monitoring, drilling guidance, subsurface extrapolation of data and data representation, storage, and manipulation are described below.

Sampling and analysis of well effluents is an important means of detecting ground water pollution. However, as described by Sanyal and Weiss (in press), this technique has some drawbacks. Water sampled from an uncased well represents a mixture of water from various permeable horizons rather than from an individual horizon. This situation is undesirable if water quality varies significantly with depth within the borehole. A sample from a cased well represents only the water at the perforated interval. One way of obtaining a continuous vertical profile of water quality with depth is to combine borehole logging with well effluent sampling and analysis in both open and cased holes.

Well logs can reduce drilling expenses by guiding the location and construction of drill holes. They also provide means of vertical and horizontal extrapolation of data derived from these holes. Because the data are immediately accessible, their quality can be assessed during the logging operation and additional data can be obtained at important depth intervals. Periodic logging can permit observation of temporal changes in the ground water quality and flow paths, rock characteristics and the well condition caused by injection or some other mechanism.

The graphic form of a well log permits quick visual interpretation, data comparison and decision making at the site. Data can be digitized in the field or office which permits transportation by radio or telephone and storage on magnetic tape. In this form, data are readily available and can be correlated with data from other wells. This permanent recording also allows for the subsequent investigation of some geologic or hydrologic factor not considered while the hole was being drilled.

4.1.1 Well Logging Tools

Well logging tools can be divided into four general categories: electric, nuclear, acoustic and specialized tools. Those which have been used widely in the petroleum industry and are readily obtainable are listed in Table 4.1. The table also gives descriptions of the parameters measured by the log and

TABLE 4.1 COMMERCIAL WELL LOGGING TOOLS

TYPE OF EQUIPMENT	PROPERTIES MEASURED	APPLICATIONS	COMMENTS
ELECTRICAL TOOLS			All electrical tools must be used in open or nonmetallic cased holes
Spontaneous potential log	Records natural electric potential developed between borehole fluid and rock materials[7]	Geologic correlation, bed thickness determination, permeability, formation water quality,[2] pore geometry, thickness of producing aquifer[5]	Can only be run in holes filled with a conducting fluid,[2] poor results in highly resistive formations, not affected by washout holes or deep or variable invasion[4]
Resistivity logs	Records electrical resistance of a known or assumed volume of earth materials under the direct application of an electric current[2]	Porosity, permeability, formation water quality, pore geometry, lithology, thermal conductivity, heat capacity, thickness of producing aquifer[5]	Can only be run in holes filled with a conducting fluid[2]
-Single point devices	Measures resistance of borehole fluid as it is affected by the resistance of the surrounding rock[7]	Lithology, geologic correlation, fracture location[2]	Can record a large range of rock resistance[2]
-Normal devices	Short normals--measures apparent resistivity of invaded zone. Long normals--measures apparent resistivity beyond the invaded zone[2]	(Short normal device) vertical lithologic detail[2] (Long normal device) formation water quality in clastic rocks, permeability of clastic aquifers[7]	Poor results in highly resistive rocks[7]
-Lateral devices	Measures formation resistivity beyond invaded zone[7]	Correlation, lithology,[2] formation water quality, porosity	Best results in thickly bedded formations,[2] useful in resistive formations,[4] large radius of investigation[7]
-Focused devices	Measures resistivity of a thin segment of formation[1]	Correlation, formation water quality[1]	Useful for high formation resistivities, good vertical resolution[7]
Induction log	Records the conductivity of subsurface formations and formation fluids[1]	Porosity, water saturation, boundaries of beds,[1] formation water quality, lithology	Can be used in empty holes or with nonconducting fluids, not good in highly resistive formations,[2] drilling mud must have higher resistance than formation fluids[3]
Nuclear magnetism log	Induces magnetic polarization and measures relaxation time of nuclei in free fluid	Fluid identification,[1] correlation, quantitative measure of effective porosity[3]	Very small radius of investigation, can be used with nonconducting fluids, will not work if natural magnetism of formation is large or if borehole is seriously out of gauge[3]
Fluid conductivity log	Measures the conductivity of in-hole fluids[2]	Formation water quality, aids in interpretation of standard electric logs, locates zones of fluid entry or discharge of fluids of varying salinities[2]	Must wait for borehole fluids to attain chemical equilibrium[2]
Electromagnetic (induction) casing thickness log	Measures the differential casing thickness with respect to normal casing thickness	Variations in casing thickness, location of corrosion damage, estimation of economic life remaining in casing[4]	Relative differences in casing thickness of a 10^{-3} cm can be determined,[1] except for new casings quantitative thickness measurements are unobtainable, useful for old well evaluation, can be run in empty holes
Dielectric constant log	Measures travel time and attenuation rate of electromagnetic waves propagated through the formation	Water saturation, porosity	Evaluation of water saturation and porosity practically independent of water salinity except in ranges close to saturation[6]

Table 4.1 (continued)

TYPE OF EQUIPMENT	PROPERTIES MEASURED	APPLICATIONS	COMMENTS
NUCLEAR TOOLS			All radioactive tools may be used in open or cased holes
Natural gamma ray log	Records the amount of natural gamma radiation emitted by formation (U^{238}, Th^{232}, K^{40} plus daughter products)[2]	Lithology, stratigraphic correlation,[2] porosity, permeability[5]	Best use in moderate-sized holes with no washout zones[4]
Gamma spectrometry log	Records energy distribution of natural gamma radiation[2]	Lithology, stratigraphic correlation, identification of artificial radioisotopes in water,[2] useful for identifying fracture zones in crystalline rocks[7]	Especially useful for lithologic identification of crystalline rocks[7]
Gamma-gamma density log	Records the intensity of gamma radiation from a source in the probe after it has backscattered and attenuated within the borehole and surrounding rocks[2]	Lithology, bulk density, total porosity, locations of cavities behind well casing,[2] thickness of producing aquifer, thermal conductivity, heat capacity, sonic velocities,[5] location of casing collars and position of cement behind casing, water level, significant changes in fluid density[2]	Used with sonic logs, can determine fracture porosity,[4] especially useful for lithologic identification of crystalline rocks[7]
Neutron log	Counts number of neutrons present at different energy levels or the number of gamma photons produced by neutron reactions[2]	Moisture content (above water table), total porosity (below water table),[2] lithology; hydrogen, chlorine or silicon density;[4] permeability, formation water quality, pore geometry, thickness of producing aquifer[5]	Can be used in fluid-filled or empty holes; used with sonic logs, can determine fracture porosity,[4] large radius of investigation[1]
Pulsed neutron log	Measures thermal neutron decay time[1]	Chlorine density, porosity, water saturation,[1] detection of channeling behind casing,[4] formation water quality (determination of boron, lithium, silica, salts)	Formation water salinity should be high and porosity greater than 15%[4]
Neutron activation log	Measures and identifies activation- gamma radiation from decay of neutron-activated elements[1]	Elemental density (carbon, oxygen, silica, aluminum, iron, calcium, magnesium),[8] lithology,[1] formation water quality in known lithologies	Most effective technique of detecting minute quantities of various elements, however, log cannot distinguish if element contained in rock or fluid[2]
ACOUSTIC TOOLS			All acoustic tools must be used in liquid-filled holes
Borehole televiewer	Takes an oriented acoustic "photograph" of borehole wall in the form of a continuous well log[6]	Fracture and vug location (their number, size and orientation), formation dip, lithology; diagnosis of drilling, testing and production problems[6]	Provides a substitute for coring in highly fractured formations, resolution of fractures to 0.8 mm wide[10]
Cement bond log	Records P-wave attenuation[1]	Homogeneity of cement,[3] cement bond to casing and borehole wall, detection of microannulus or channeling behind casing and location of cement top[4]	Data can be questionable in casings 40 cm in diameter or larger[9]
Sonic logs			Cannot be used in empty holes;[2] have been employed in cased holes with up to 50% cement bond,[13] borehole should be to gauge,[3] useful in low resistivity formations used with gamma-gamma density or neutron logs can estimate fracture porosity in known lithologies[4]
-Acoustic velocity	Records compressional and shear wave velocities	Porosity,[4] (of intergranular formations), fracture orientation, mechanical properties of rock,[2] pressure, formation water quality, pore geometry, thermal conductivity, heat capacity, thickness of producing aquifer,[5] lithology[4]	
-Amplitude	Records compressional and shear wave amplitudes	Cement bond quality, location of fractures,[2] pore geometry, lithology[5]	

Table 4.1 (continued)

TYPE OF EQUIPMENT	PROPERTIES MEASURED	APPLICATIONS	COMMENTS
Acoustic caliper	Records wave reflection	Accurate hole diameter in several directions, orientation of fractures, location of vugs and bed boundaries in open holes and casing inspection in cased holes	Useful in large boreholes[1]
SPECIALIZED TOOLS			
Caliper log	Produces a profile of borehole size variation in open holes, casing size variation in cased holes	Location of fracture caving and cavity locations, lithology and estimates of required cement volumes in open holes, interior casing deterioration in cased holes, hole diameter correction factors for other log interpretations	5 to 20 cm hole diameter limitation with ±5 mm accuracy[4]
Temperature log	Records temperature of well bore as a function of depth	Temperature, permeability, thermal conductivity, heat capacity, geothermal gradient, location and thickness of zones of fluid entry or discharge in borehole, location of cement top, detection of fluid flow behind pipe and casing, correction factors for other log interpretations	Accuracy to 0.3°C[4]
Flowmeter log	Records fluid velocity versus depth	Determines contribution of each zone to total production or injection, indicates changes in flow patterns[4]	Inflatable packer-type flowmeter useful for low flow rates, continuous-type flowmeter useful for high flow rates[4]
Dipmeter log	Resistivity of a thin section near the borehole to produce 3 to 4 correlation curves on different sides of the hole[4]	Formation dip relative to borehole,[4] orientation of fractures[12]	Electrically conductive mud must be used in borehole and the borehole must be relatively free of cavings[1]
Gravity meter log	Records gravity differential between any two sections in the borehole[1]	Density, porosity, average bulk density[1]	Very large radius of investigation[1]
Drilling time log	Records of times drilling starts and stops, depths and times connections are made, drilling rate and ambient and borehole temperatures	Lithology, stratigraphic correlation, formation depth, correction factors for other logs	
Mud log	Identification of mud and drilling cuttings	Lithology, stratigraphic correlation, formation depths, drilling control	
Fluid pressure log	Measures fluid pressure as a function of depth	Well control, borehole fluid movement	

Table 4.1 (continued)

TYPE OF EQUIPMENT	PROPERTIES MEASURED	APPLICATIONS	COMMENTS
Injectivity profile	Under injection conditions, plots water loss as a function of depth[2]	Determines relative magnitudes of permeability under an imposed hydraulic stress[2]	
Directional survey	Records angle borehole makes with vertical as a function of depth and drift azimuth[1]	Bottom hole location with reference to surface location[1] and orientation of hole in ground	
Radioactive or chemical tracer techniques	Searchs for and records the level of an introduced tracer	Borehole fluid velocity, detection of flow behind the casing,[4] ground water flow patterns between wells, permeability, identification of production or injection horizons	Radioactive tracer techniques best for measuring very low flow rates
Borehole audio tracer survey	Measures the level of sound generated by fluid flow behind the casing[11]	Locates and estimates quantity of fluid flow behind casing, flow rate[11]	
Gradiomanometer*	Measures the average pressure gradient over 60 cm intervals	Specific gravity profile, depth of pressure gradient changes, location of fluid contacts,[4] two-phase fluid flow, slippage velocities and volumetric flow rate from each zone[1]	Temperature and pressure changes must be corrected, run with continuous flow meter for multi-phase fluid flow interpretation,[4] dynamic range of 0 to 1.6 g/sq cm with 0.03 g/sq cm accuracy[1]
Formation Interval Tester*	Perforates casing and recovers sample of formation fluid sealed under pressure, measures flowing and shut-in pressures[4]	Formation water quality	Can seal perforations made[4]
Formation sampler	Side wall coring	Porosity, permeability, mechanical properties, heat conductivity, electrical resistivity	
Fluid sampler	Collects borehole fluid sample and measures in situ formation pressures and temperatures[1]	Borehole water quality	

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[1] Baker, et al. (1975)

[2] Keys and MacCary (1971)

[3] Wyllie (1963)

[4] Schlumberger (1969, 1970, 1974, 1975, 1977)

[5] S. K. Sanyal (pers. comm., 1978)

[6] Calvert, et al. (1977)

[7] West, et al. (1975)

[8] Ferronsky, et al. (1968)

[9] Keys and Brown (1973)

[10] Zemanek, et al. (1970)

[11] Britt (1976)

[12] Pettitt (1975)

[13] Muir and Zoeller (1967)

those which may be derived from log analysis and interpretation; comments concerning the tool's limitations and advantages; and, where available or applicable, its precision.

These tools, when used within their design limits, provide direct measurements of:

1. borehole size and depth;
2. temperature, pressure and fluid flow within the borehole; and
3. resistivity, sonic wave velocity and amplitude, bulk density, gamma-ray intensity, neutron-capture cross section, and self-potential of penetrated formations.

Other parameters, which must be calculated, derived or inferred from the log record include:

1. lithology, porosity, and permeability of penetrated formations;
2. formation dips, pressure, density and mechanical properties;
3. heat flow in the borehole;
4. borehole fluid characteristics;
5. casing condition;
6. cement bond quality;
7. borehole orientation; and
8. fracture detection and delineation.

A complete discussion of the principles and interpretation techniques of well logging methods is given by Keys and MacCary (1971), Schlumberger (1970, 1974), Wyllie (1963) and several other sources. A brief survey of these methods is presented below.

The electrical logging tools developed by the Schlumberger brothers in the late 1920s were the first to be extensively used by the petroleum industry. Downhole voltage and resistance are measured. Electrical tools are limited to use in uncased or fiberglass-cased holes. The logs can be used to define the lithology for stratigraphic correlation or as indicators of water quality; they are especially useful in ground water investigations.

Radioactive logging is based on radiation scattering or radioactive decay of unstable nuclei and the detection of the emitted radiation. The radioactivity may be either natural or induced, and can result from the injection of an isotope used as a tracer. Because certain types of radiation are very penetrating, these logs may be used in cased or uncased holes and in the presence or absence of borehole fluids. Radioactive logging techniques are useful for defining rock and fluid properties in both cased and uncased holes; monitoring changes in water quality in cased holes; detecting effluent leakage from older wells; and determining ground water flow patterns between wells.

Acoustic logging was developed in response to the need to measure in situ sonic velocities of subsurface formations. These tools measure compressional (P) and/or shear (S) wave velocities and signal attenuation which are used to determine fractures, porosity, cement bond quality, borehole size and condition, and mechanical properties of the rock such as bulk modulus and Young's modulus. Acoustic logs are run in uncased, fluid-filled holes; however, some acoustic porosity logs have been run successfully in cased holes (Muir and Zoeller, 1967).

The specialized tools have been developed to measure a variety of parameters in the borehole, such as temperature; fluid velocity, pressure and density; formation dip; and borehole shape, size, condition and orientation.

Interpretation of rock and fluid properties from well logs is enhanced by composite interpretation of several logs for the same parameter. As stated by Keys and MacCary (1971):

> As a general rule, the more types of geophysical logs that are available for a single well and the more wells that are logged within a given geohydrologic environment, the greater the benefits that can be expected from logging. The synergistic character of logs is due to the fact that each type of log actually measures a different parameter, and when several are analyzed together, each will tend to support or contradict conclusions drawn from the others. Similarly, a large number of wells logged in one ground water environment will provide a statistically meaningful sample of the environment and reduce the chance of interpretive errors.

4.2 LOG INTERPRETATION PHILOSOPHIES

Well logging was developed specifically to service the petroleum industry in its particular environments for its special problems. The objectives, operation, analysis and interpretation of well logs in and around geothermal systems are considerably different than those in petroleum systems. The fundamental differences arise from the diverse physical characteristics of the two types of reservoirs. Petroleum reservoirs most often occur in relatively soft, sedimentary rocks, with intergranular porosity, at temperatures less than 150°C (300°F) and water saturation less than 100%. Geothermal reservoirs usually occur in hard, saturated, fractured igneous and metamorphic rocks at relatively high temperatures. Except for Imperial Valley, California, very few hydrothermal systems of commercial interest are known to occur in sedimentary rocks. Because of these differences, direct transfer of petroleum logging technology to geothermal environments is impossible. The problems involved in developing the technology for geothermal environments are discussed in detail by Sanyal and Meidav (1977) and summarized below.

4.2.1 Log Interpretation Problems

The most important objectives of petroleum well logging are determination of reservoir lithology, porosity, permeability and hydrocarbon saturation. For this reason, the bulk of research for commercial logging tools has been confined to developing newer and better tools and interpretation techniques for measuring these parameters. In geothermal well logging, the most important objectives are the detection of large-scale faults and fractures, and the determination of porosity (usually fracture-type), equilibrium formation temperature, and the thermal and elastic properties of reservoir rocks. These along with the assessment of water quality, necessary for ground water investigations, have drawn little attention in the petroleum industry, and are relatively undeveloped.

General Problems--

Core data from geothermal wells, necessary for accurate log interpretation, are scarce. Only a few dozen geothermal well logs and core analysis reports are publicly available. The major reason for the lack of geothermal cores, to date, is their expense. Presently the cost of coring is about $1,500 per meter compared to about $300 per meter for routine drilling (Los Alamos Scientific Laboratory, 1978).

Although it is advisable to run as many logs as economically possible, a full log suite may not be run in all geothermal wells because of cost consideration or operational problems. This makes lithology identification and porosity evaluation difficult.

Another problem is that the present state of knowledge of the effects of high temperature, pressure and geothermal fluid chemistry on reservoir rocks is very primitive and the use of core data to normalize well log data may not be justifiable in many geothermal situations.

Assessing Log Quality--

The first task in geothermal well log interpretation is assessing the log quality. Careful checking, crosschecking and analysis are required to pinpoint any problems in the log. It is important to have accurate drillers' logs, including records of times at which drilling stopped, circulation stopped and various logging tools reached the bottom; and the corresponding temperature measurements. Unless these data are recorded, it is difficult to assess the formation temperature at the time of logging and other factors which affect rock and fluid properties and log responses.

Sanyal and Meidav (1977) list several problems associated with log quality in geothermal reservoirs which are also known in the petroleum industry. These can usually be resolved when they are detected. However, other types of problems, described below, cannot be easily resolved.

Unfamiliar Lithology--

The state-of-the-art of well logging techniques and interpretation is adequate for geothermal reservoir systems in sedimentary environments, although some modification is needed in analysis to account for possible contact metamorphism, hydrothermal alteration or the presence of intrusives. Conventional interpretation methods have been used with success in shallow sedimentary ground water basins. However, an unfamiliar lithology poses several problems in log interpretation. Standard calibration and interpretation charts, log interpretation equations and overlay and crossplot concepts for well log analysis were designed for typical petroleum reservoir lithology: sandstone, shale, limestone, dolomite and anhydrite. These methods are often inadequate for nonsedimentary geothermal reservoirs where crystalline igneous and metamorphic rocks, glassy or crystalline volcanic rocks, and welded volcanic rock material are often encountered. Empirical correlations so often used for well log interpretation in sedimentary environments, are yet to be developed for geothermal well log interpretation.

For example, in the Raft River geothermal field, the points on some multiple porosity crossplots fall outside the range of standard charts. Lithology and porosity values can also change abruptly with depth in a sedimentary section because of zones of hydrothermal alteration or igneous intrusions which are often encountered in geothermal environments. It is often difficult to develop a useful empirical porosity-permeability correlation from core data because of fractures and abrupt changes in lithology.

Lack of calibration data for such lithologies also presents a problem in interpretation. When an "unusual" rock type is encountered, the log response may appear strange and some correction may be necessary. For most unfamiliar lithologies, such corrections cannot be estimated. For example, in the Hot Dry Rock Project Well No. 2, some zones increase in bulk density without corresponding decrease in the sonic travel time. This response was apparently a result of the presence of mafic rocks encountered in these zones, having higher electron densities than the medium used to calibrate the density logging tool (West, et al. 1975). Calibration data were not available to resolve the problem. Such "strange" responses can be expected from geothermal well logs run in unfamiliar lithology.

Conventional complex lithology analysis aided by computer processing, crossplots and histograms can be applied to igneous and metamorphic rock formations. However, matrix properties, such as bulk density, sonic travel time, matrix neutron porosity and neutron cross section of these "unfamiliar" lithologies are often unavailable or available only for a few of the minerals which form these rocks (S. K. Sanyal, pers. comm., 1978). In addition, the mineral composition of these rocks may vary considerably from zone to zone. For sedimentary lithology, these logs will be as usable as in the petroleum industry. Sanyal and Meidav (1977) summarize the utility of some conventional well logs for geothermal reservoirs of the nonsedimentary lithology (Table 4.2).

4.2.2 Geothermal Reservoir Classification for Well Log Interpretation

The Department of Energy, in conjunction with the Los Alamos Scientific Laboratory, has initiated a program to develop log interpretation techniques for geothermal environments. As part of this effort, a proposed classification scheme for geothermal reservoirs is being developed (S. K. Sanyal, pers. comm., 1978). Reservoirs are grouped into a small number of classes to serve as a basis for the development of distinct sets of log responses and typical log analyses problems for each class. This system can be extended to well logging interpretation techniques for

TABLE 4.2 UTILITY OF VARIOUS WELL LOGS IN NON-SEDIMENTARY LITHOLOGY

(Sanyal and Meidav, 1977)

LOG TYPE	COMMENTS
1. Self Potential	Often poorly developed; Unreliable in massive igneous or metamorphic sections; Works in some fractured igneous and metamorphic sections; Usually not useful for correlation.
2. Electrical Resistivity	Mostly off scale in massive igneous and metamorphic sections; Can be helpful in locating fractures; Short spacing resistivity may be affected by the short-circuiting effect of borehole fluid; Focussed devices may be helpful for very resistive formations.
3. Acoustic Devices	BHC* sonic log works well unless there is significant hole enlargement; May be useful for correlation; Matrix velocity values may not be known; Useful for overlay and crossplot techniques; Full-wave sonic log valuable in locating fractures; Borehole televiewer valuable for locating fractures and delineating its orientation.
4. Neutron Devices	Responses from unfamiliar lithology may be difficult to assess; May be useful for correlation.
5. Density	Useful in estimating porosity and lithology; Caving may be a problem; Log response from unfamiliar lithology difficult to assess; Useful for correlation.
6. Gamma Ray	Useful for correlation; Spectral gamma ray useful for lithology identification.
7. Drilling Log	Drilling rate log useful for locating fracture zones and changes in lithology; Drill cuttings log useful for lithology identification; Useful for correlation.
8. Caliper	Useful in resolving many log quality problems; 6-arm caliper can be used in determining dip of fracture-zone washout ; Use in judging hole condition.
9. Dip Meter	Not always useful because of lack of laminated structure; Dip of fractures may be unreliable.
10. Temperature	Useful for assessing temperature gradient, and other standard uses of temperature log.

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defining baseline conditions of hydrologic systems in geothermal environments. In this system, reservoirs are defined according to:

I) Fluid type and temperature. Liquid- and vapor-dominated systems have different log responses as do oil and gas reservoirs. Temperature affects most rock and fluid properties: in geothermal reservoirs, well temperatures often exceed the tolerance of many logging tools. However, injection and monitoring wells are expected to be within the tolerance range of most tools (175°C [350°F]).

II) Lithology. Lithology is the most important factor affecting log response, as the major part of reservoir bulk density is the rock matrix.

III) Overall geologic factors. Each geologic province has a rock and fluid assemblage particular to that area and associated with certain characteristic log responses. This type of classification is similar to the use of names such as "Gulf Coast, Rocky Mountains, California, North Sea," etc. in the petroleum industry.

IV) Pore geometry. The nature and geometry of pore spaces have strong influence on sonic, electric and nuclear log responses from a formation. In geothermal reservoirs, fracture, or vesicular porosity often exists and effective and total porosity values for these reservoirs will differ.

V) Fluid chemistry. More diverse than most oil field waters, geothermal waters vary both in TDS concentration and chemical composition. Log interpretation methods may need correction if major constituents other than sodium chloride are present.

This classification scheme is detailed in Table 4.3.

Some examples of well known geothermal areas typed by this system are given in Table 4.4. With the increasing use of well logs in the geothermal industry and the accumulation of core data from geothermal wells, interpretation of log response in nonsedimentary environments will develop. Well log data

TABLE 4.3

GEOTHERMAL RESERVOIR CLASSIFICATION SCHEMES
(S. K. Sanyal, pers. comm., 1978)

I. According to Fluid Type & Temperature:
  - A. Steam
  - B. High-Temperature Water (>400°F)
  - C. Moderate-Temperature Water (300-400°F)
  - D. Low-Temperature Water (<300°F)
  - E. Dry

II. According to Lithologic Type:
  - A. Sedimentary
  - B. Metamorphic
  - C. Igneous (crystalline & glassy)
  - D. Volcanic Ash and Associated Sediments, Tuff
  - E. Breccia
  - F. Hydrothermally Altered

III. According to the Geologic Province:
  - A. Basin & Range
    - a. Wasatch Front
    - b. Central
    - c. Western Margin
  - B. Northwest Volcanic
    - a. Snake River
    - b. Cascade Range
    - c. Other
  - C. Salton Trough
  - D. Northern California Coast Range
  - E. Rio Grande Rift & Colorado Plateau Borderland
  - F. Hawaii
  - G. Alaska

IV. According to Pore Geometry:
  - A. Sedimentary Intergranular Porosity
  - B. Fracture
  - C. Vesicular or vuggy porosity

V. According to Salinity and Fluid Chemistry:

  - A. Low salinity (<5,000 ppm)
  - B. Moderate salinity (5-35,000 ppm)
  - C. High salinity (35-100,000 ppm)
  - D. Hyper saline (>100,000 ppm)
  - E. Dry

TABLE 4.4 TYPING OF WELL-KNOWN GEOTHERMAL RESERVOIRS
(according to Classification Schemes in Table 4.3)
(S. K. Sanyal, pers. comm., 1978)

Reservoir	Location	Type
Salton Sea	Imperial County, California	IB, IIA/F, IIIC, IVA/B, VD
Brawley	Imperial County, California	IB, IIA, IIIC, IVA, VC
Heber	Imperial County, California	IC, IIA, IIIC, IVA, VB
East Mesa	Imperial County, California	IC, IIA, IIIC, IVA, VB
Dunes	Imperial County, California	ID, IIA, IIIC, IVA, VB
Cerro Prieto	Baja California, Mexico	IB, IIA, IIIC, IVA, VB
The Geysers	Sonoma County, California	IA, IIB, IIID, IVB, VA
Coso Hot Springs	Inyo County, California	IC, IIB/C, IIIAc, IVB, VB
Mono-Long Valley	Mono County, California	IC, IIC/D, IIIAc, IVB, VA
Kilauea	Hawaii	IB, IIC/F, IIIF, IVB/C, VA
Raft River	Cassia County, Idaho	ID, IIA/C/D, IIIBa, IVA, VA
Mountain Home	Elmore County, Idaho	IC, IIC/D, IIBa, IVB/C, VA
Yellowstone	Park County, Wyoming	IA/B, IIC/D/F, IIIBc, IVB/C, VA
Roosevelt Hot Springs	Beaver County, Utah	IB, IIC, IIIAa, IVB, VB
Valles Caldera	Sandoval County, New Mexico	IB, IIC/F, IIIE, IVB, VB
Fenton Hill	Sandoval County, New Mexico	IE, IIC/F, IIIE, IVB, VE
Brady's Hot Springs	Lyon/Churchill Co., Nevada	IB, IIA/C/D/F, IIIAc, IVA/B, VA
Steamboat Springs	Washoe County, Nevada	IC, IIC/D/F, IIIAc, IVB/C, VA
Beowawe	Lander/Eureka Co., Nevada	IB, IIC/D/F, IIIAb, IVB, VA
Klamath Falls	Klamath County, Oregon	ID, IID/E, IIIBa/Ac, IVB, VB

will provide valuable information for exploration and production of the resource, for understanding subsurface injection environments, and for monitoring ground water degradation.

4.3 WELL LOGGING AND GROUND WATER MONITORING

Well logging can play a vital role in a ground water monitoring plan. It can:

1) aid in the construction of injection and observation wells;

2) help define the baseline conditions of the subsurface injection environment, nearby ground water systems and their interrelationship;

3) monitor the condition of the injection well; and

4) aid in monitoring wastewater flow patterns and possible degradation of fresh ground water throughout the monitoring network

These applications of well logs are discussed below and are summarized in Tables 4.5, 4.6, 4.7 and 4.8.

Well design and construction factors such as hole diameter, drilling method, casing, mudcake and degree of mud invasion affect log quality (Keys and Brown, 1973). Where logging is to play an important role in the monitoring plan, wells should be designed for the maximum efficiency of logging.

4.3.1 Well Construction

Wells must be carefully constructed to intersect a determined horizon for injection and monitoring operations. Directional surveys are used to guide the drilling direction of the well, determine the position of the hole in the ground, and accurately locate the bottom of the hole. Caliper logs reveal the actual shape and condition of the borehole, and allow estimates of the volume of cement needed for casing installation. After casing installation, temperature and gamma-gamma logs can be used to establish the position of the cement behind the casing (Fig. 4.1; Keys and MacCary, 1971). Cement bond logs show the degree of bonding between the casing and cement and the cement and formation. The information from both of these logs can determine whether the cement in the annulus provides an adequate seal between the casing and borehole. If this seal is not adequate, vertical migration of fluids may occur and contaminate surrounding aquifers.

TABLE 4.5 WELL LOGGING FOR WELL CONSTRUCTION

OBJECTIVE	LOGGING TOOL
Orientation of borehole and bottom-hole location	Directional survey
Shape and condition of borehole (location of caving or washout zones)	Caliper log
Volume of cement needed for casing installation	Caliper log
Position of grout behind casing	Temperature and gamma-gamma logs
Cement bond integrity	Cement bond and temperature logs
Top of cement	Cement bond and temperature logs
Depths of casing, tubing, screens and perforations	Casing-collar locator
Condition of casing	Caliper, borehole televiewer, casing inspection logs
Casing leaks and/or plugged screens	Tracer techniques, flowmeter log
Leaks in annular cement	Tracer techniques, temperature and cement bond logs and gamma-gamma log in older wells
Guide to screen setting or perforations	All logs which provide data on lithology, porosity and permeability of units (see Table 4.6), flowmeter and temperature logs

TABLE 4.6 WELL LOGGING FOR DEFINING BASELINE CONDITIONS
(modified from Keys and MacCary, 1971)

OBJECTIVE	LOGGING TOOL
Lithology and stratigraphic correlation of aquifers and associated rocks	Electric, sonic, nuclear and caliper logs in open holes,[1] nuclear logs in cased holes
Total porosity or bulk density	Calibrated sonic logs in open holes, calibrated gamma-gamma or neutron logs in cased holes
Effective porosity	Resistivity and nuclear magnetism logs in open holes
Secondary porosity and fracture identification	Injectivity profiles and caliper, resistivity, acoustic, borehole televiewer and dipmeter logs in open holes
Permeability	No direct measurement made by logging. May be related to porosity and sonic, flowmeter and temperature logs; injectivity profiles or tracer techniques
Location of water level or saturated zones	Electric and temperature logs in open holes, temperature, neutron and gamma-gamma logs in cased holes
Moisture content above the water table	Neutron logs in open and cased holes
Direction, velocity and path of ground water flow	Single well and multi-well tracer techniques, temperature and flowmeter logs in open and cased holes
Source and movement of water in a well	Injectivity profile, tracer techniques or flowmeter logs during pumping or injection, temperature logs
Chemical and physical characteristics of water (water quality, salinity, temperature, density, viscosity)	Electric logs in open holes, temperature, neutron, pulsed neutron and neutron activation logs and Formation Interval Tester* in cased holes

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[1] Electric logs may also be run in fiberglass cased holes.

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TABLE 4.7 WELL LOGGING FOR INJECTION WELL MONITORING

OBJECTIVE	LOGGING TOOL
Condition of injection well tubing, casing and cement	Casing inspection, cement bond and caliper and borehole televiewer
Injection pressure and flow rates	Fluid pressure and flowmeter logs
Location and direction of waste dispersion, dilution and movement from well	Temperature, flowmeter and fluid conductivity logs, tracer techniques
Change in relative formation water quality and in brine/fresh water interface	All logs providing data on the chemical and physical characteristics of water (see Table 4.6)
Leakage from the well	Temperature, nuclear, cement bond logs, radioactive tracer techniques
Aquifer solution or plugging	Nuclear logs

TABLE 4.8 WELL LOGGING FOR OBSERVATION WELL MONITORING IN GEOTHERMAL ENVIRONMENTS (modified from U.S. EPA, 1975)

WELL TYPE	OBJECTIVE	LOGGING TOOL
Constructed in receiving aquifer	Pressure in receiving aquifer	Pressure log
	Rate and direction of wastewater movement	Temperature, flowmeter and fluid resistivity logs, radioactive tracer techniques
	Geochemical changes in injected wastewater	All logs providing data on the chemical and physical characteristics of water (see Table 4.6)
	Detect shifts in fresh water-saline water interfaces	Electric and nuclear logs
Constructed in or just above confining unit	Detect leakage through confining unit	Temperature, nuclear and electric logs, radioactive tracer techniques
Constructed in a fresh water aquifer above or downgradient from receiving aquifer	Detect evidence of fresh water contamination	Temperature, electric, nuclear and all logs providing data on water quality (see Table 4.6)

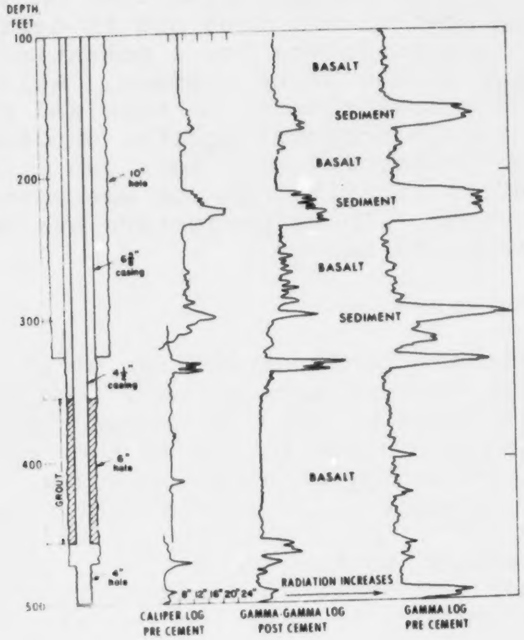

Figure 4.1 Gamma-gamma logs used to interpret position of grout behind casing, and caliper logs used to select depth for grouting and to estimate volume required. (Keys and MacCary, 1971)

The exact depths of casings, tubings, screens and perforations can be found with the casing-collar locator and the top of cement with the temperature or cement bond logs. Well logs can also be used to locate the most permeable units to set perforations and screens. Most of these logs can be analyzed at the well site to permit rapid decision making.

4.3.2 Defining Baseline Conditions

Well logs can provide essential data on subsurface geologic and hydrologic parameters and thus aid in defining baseline conditions and characteristics for a potential injection zone and for the nearby ground water systems. Well logs furnish continuous downhole measurements of rock and fluid properties which are essential to forecast aquifer conditions and predict ground water flow patterns. Well logs can also give data to predict the quantity and flow rate of wastewater acceptable to the injection horizon. These parameters are summarized on Table 4.6 and discussed below.

Lithologic Parameters--

The identification and correlation of lithologic units has been one of the prime functions of well logging in the petroleum industry. As discussed by Keys and Brown (1973), the primary task for waste injection monitoring is the prediction of waste movement. Such predicting requires an understanding of subsurface lithology, geometry and uniformity of subsurface units. The dispersion coefficient, necessary to calculate underground dispersion, is related to the geometry and uniformity of aquifers and confining beds. Continuous downhole in situ measurements of lithologic parameters by well logging also allow more accurate predictions of well and injection performance since the extrapolation of laboratory data from cores to the in situ conditions may be erroneous. As discussed above, coring is also very expensive in most geothermal environments because the formations are highly consolidated. Furthermore, in highly fractured formations, information from cores on porosity and permeability may be meaningless.

Lithology--Lithology may be determined from electric, sonic, nuclear and other logs in open holes and by nuclear logs in cased holes (Table 4.6). These logs measure differences in rock characteristics due to density, mineral composition, porosity and relative strength of units which can be interpreted to decipher lithology. For maximum effect, several different logs which measure different aspects of lithology should be run. Since a log response is not unique, background information and knowledge of regional geology in a new area is essential for correct log interpretation.

Well logs also provide a basis for delineating stratigraphy. Keys and MacCary (1973) use gamma-ray and neutron logs to correlate sedimentary units in a saline water basin (Fig. 4.2). The difference in character of both gamma-ray and neutron logs in Hole T-14 above and below 457 m (1500 ft) is apparent and marks the contact between two formations. Above this contact, the holes penetrated fine-grained clastic rocks with a few beds of anhydrite. Below 457 m (1,500 ft) lithology is dominated by mudstone with numerous anhydrite beds. Anhydrite beds show up as strong deflections to the left on the gamma logs.

Well log data can be essential to identifying aquifers and in constructing contour maps showing aquifer thickness and structure in unknown complex systems. Jones (1961a, 1961b) describes the use of natural gamma-ray and caliper logs to define the complex basalt aquifer system at the National Reactor Testing Station, Idaho. Prior to this investigation, definition of the geometry of basalt flows and interflow sediments of the Snake River Plain had not been possible. From well log data, Jones (1961b) correlated interflow sediments, identified the most permeable units and was able to construct cross sections of this very complex system (Fig. 4.3).

Since ground water temperature is rarely the same in different aquifers, temperature logs can be used to identify aquifers or perforated intervals contributing water to a flowing well. Keys and MacCary (1971) show a series of temperature logs from an unsuccessful plugged oil well in which perforated intervals contributing water to the well are clearly distinguished by temperature logs (Fig. 4.4). Log A was made before the well was perforated and shows the normal temperature gradient profile from the field. Log B was made after perforations were made and the perforated intervals between 150 to 180 m (500 to 600 ft) are clearly distinguished. Log C shows that initially most of the water moving up the casing was coming from the 175 m (575 ft) aquifer. Log D shows that, after pumping for 24 hours, the 157 m (515 ft) aquifer began to contribute some water. Temperature logs B through D all show warmer water moving up the well after the casing was perforated.

Fractures--The delineation of large-scale fractures and faults is also an important factor in defining baseline conditions. Fractures intersecting the borehole may be located by caliper, resistivity, acoustic, borehole televiewer and dipmeter logs. Fig. 4.5 shows the correlation of fracture zones between two wells by caliper logs. The repeatability of the logs made on different dates in Hole C-1 is evident. Small fractures found by the caliper at a depth of 58 m (190 ft) in Hole C-1 can be correlated with similar fractures found at 55 m (180 ft) in Hole T-5, 5 km (3 mi) distant from Hole C-1. The

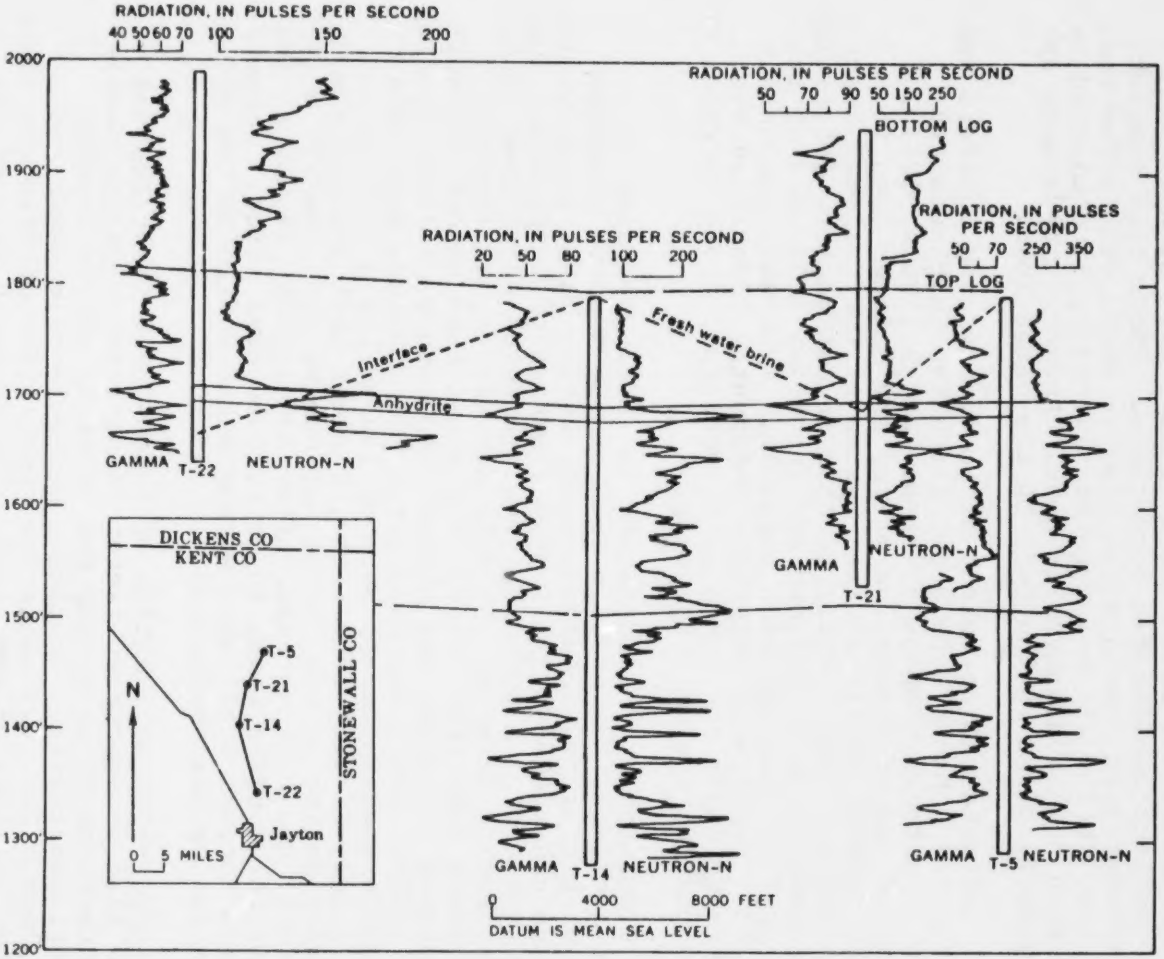

Figure 4.2 Stratigraphic correlation with gamma and neutron logs, Upper Brazos River Basin, Texas. (Keys and MacCary, 1973)

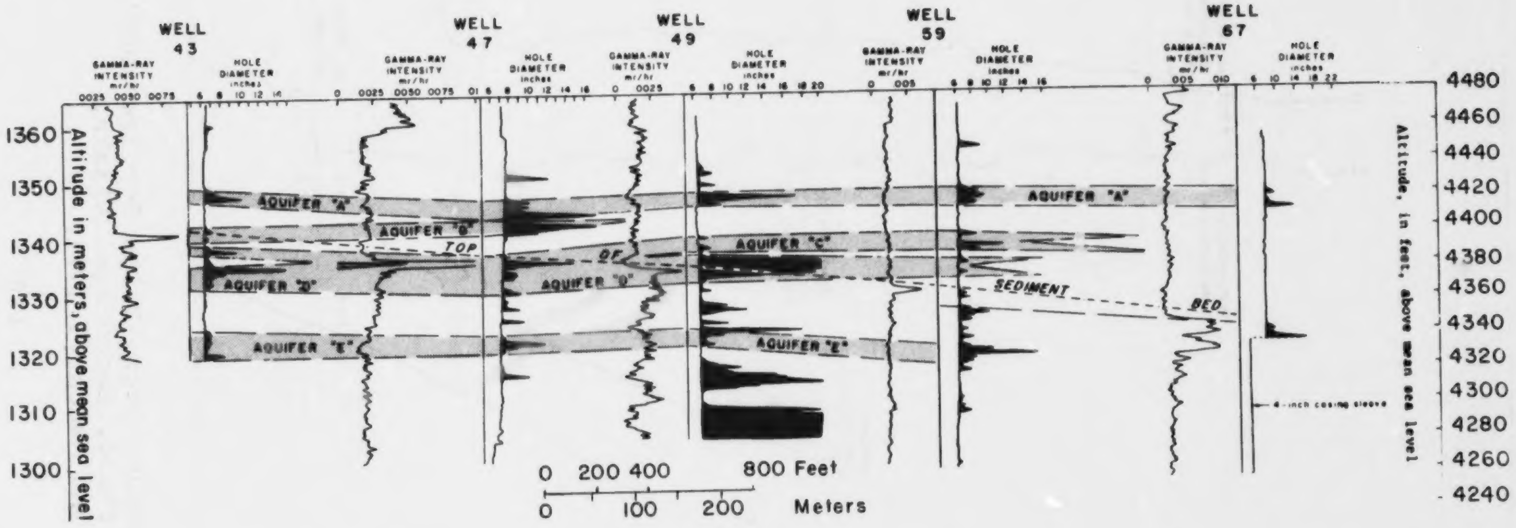

Figure 4.3 Structure and thickness of aquifers A to E based on well logs, National Reactor Testing Station, Idaho. (Jones, 1961b)

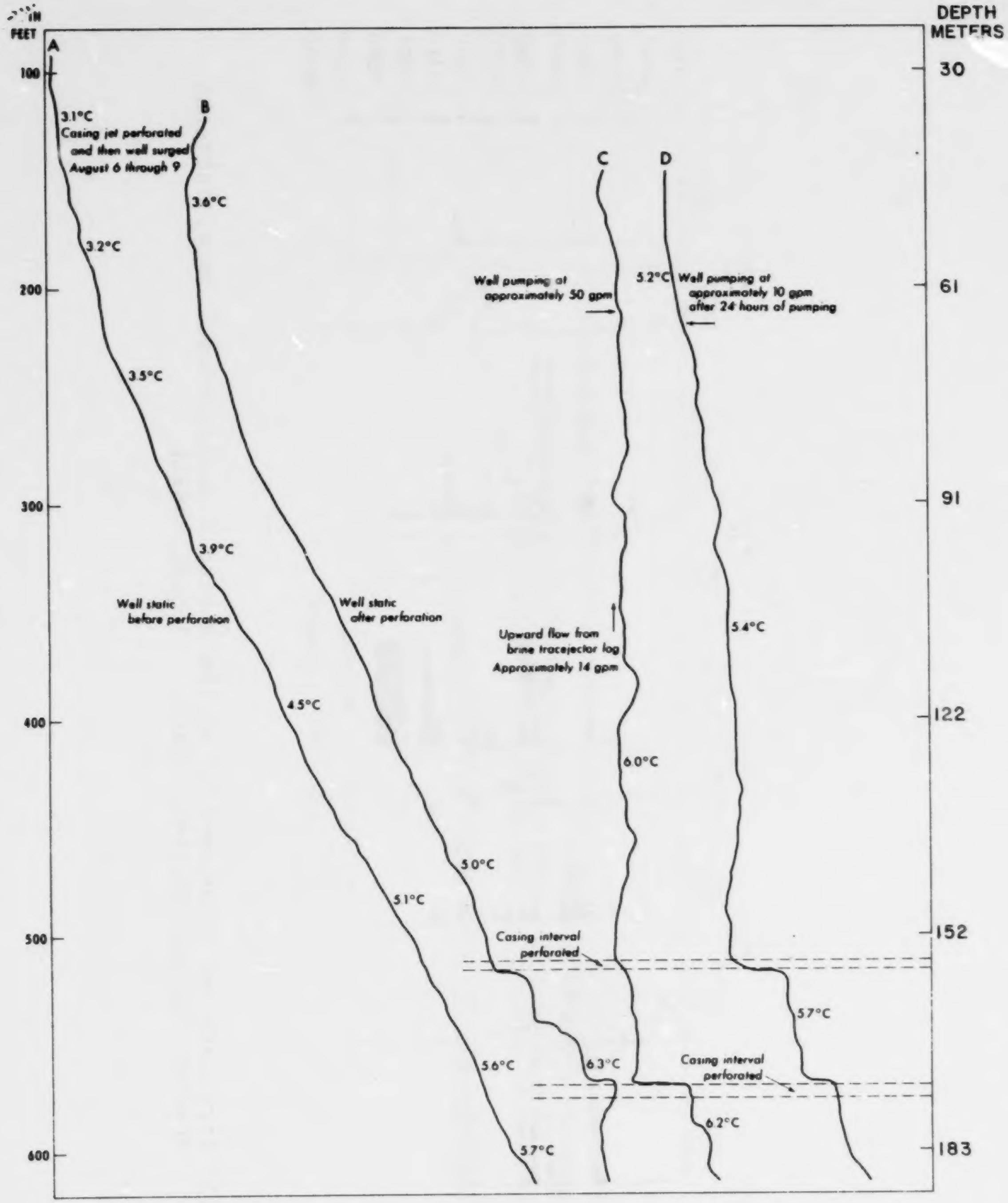

Figure 4.4 Temperature logs, Yukon Services well, Cook Inlet field, Anchorage, Alaska. (Keys and MacCary, 1971)

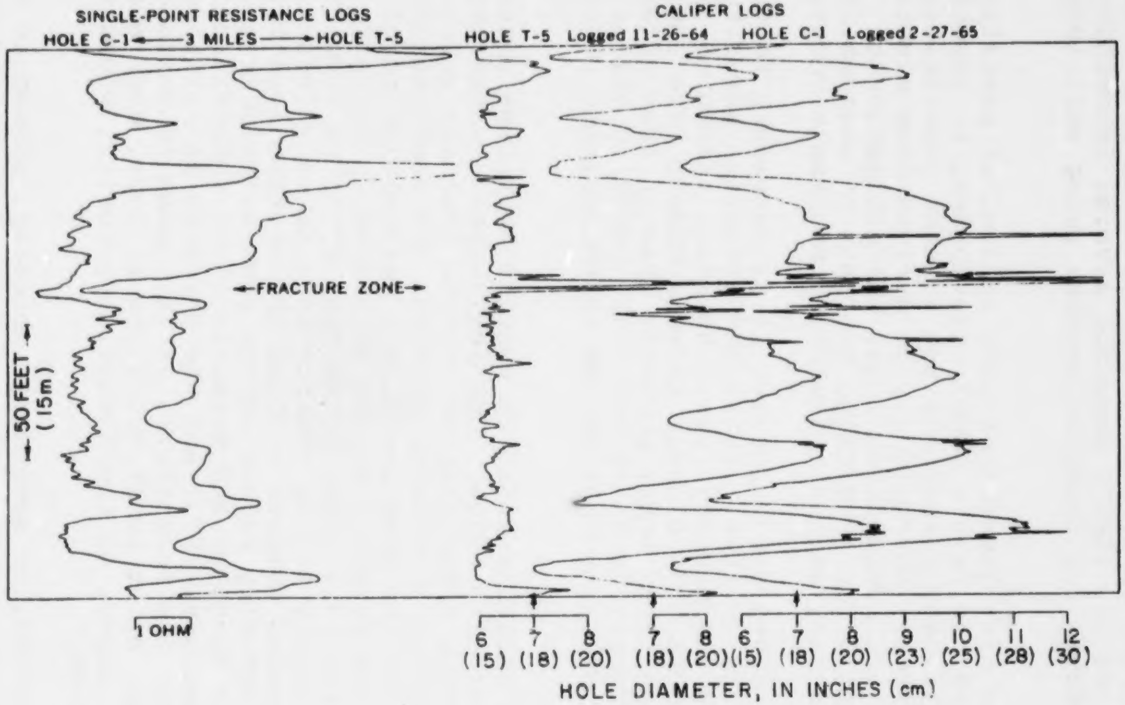

Figure 4.5 Correlation of fracture zones between rotary hole T-5 and core hole C-1 utilizing caliper logs, Upper Brazos River Basin, Texas. (Keys and MacCary, 1973)

single-point resistance logs indicate that the fracture zones in C-1 and T-5 are in the same stratigraphic position (Keys and MacCary, 1973).

Caliper and dipmeter logs may also give information on the orientation and direction of fracture propagation from the borehole. Landt, et al. (1977) describe several innovative, theoretical techniques for fracture mapping using well logging techniques.

Porosity--The distribution of pore spaces, or porosity, and permeability, which can have a local relationship to porosity, are the most significant parameters for aquifer identification and injection control. Porosity may be derived from electric, nuclear, acoustic and specialized logs. An estimation of porosity is essential for predicting the path of wastewater dispersion and velocity and in calculating reservoir volumes.

In deriving values for porosity, it is necessary to note the type of porosity present. Total and effective porosity are nearly the same in sedimentary rocks; however, fractured igneous and metamorphic rocks and volcanic rocks commonly have isolated void spaces, making their total porosity greater than effective porosity. Furthermore, in fractured rock, porosity values obtained around a well bore may not be characteristic of the reservoir.

Neutron logs indicate moisture content above the water table and total porosity below. Chemically bound water cannot be distinguished from free water on neutron logs and erroneous values may be obtained if mineral hydrates are encountered. Gamma-gamma logs are the most useful for determining total porosity. Effective porosity can be estimated by nuclear magnetism logs. Fig. 4.6 shows porosities measured from rock cores in the laboratory and by neutron logs in an adjacent hole. Once calibrated against a core, the neutron logs can be used to estimate porosity values in the same lithologic units, provided that hole diameter and borehole fluid composition are known (Keys and MacCary, 1973) and the porosity is relatively constant throughout the formations, as is common in sedimentary rocks. Cross plots of at least two types of logs, each evaluating a different aspect of the formation porosity, yield the most accurate values.

Zones of fracture, or secondary, porosity, common to most geothermal reservoirs, may be delineated by electric, acoustic, caliper and dipmeter logs in uncased holes. Effective fracture porosity in highly resistive plutonic and metamorphic saturated rock may be identified from resistivity logs, since the water filled fractures are relatively conductive. Single-point resistivity logs can give accurate values for effective fracture

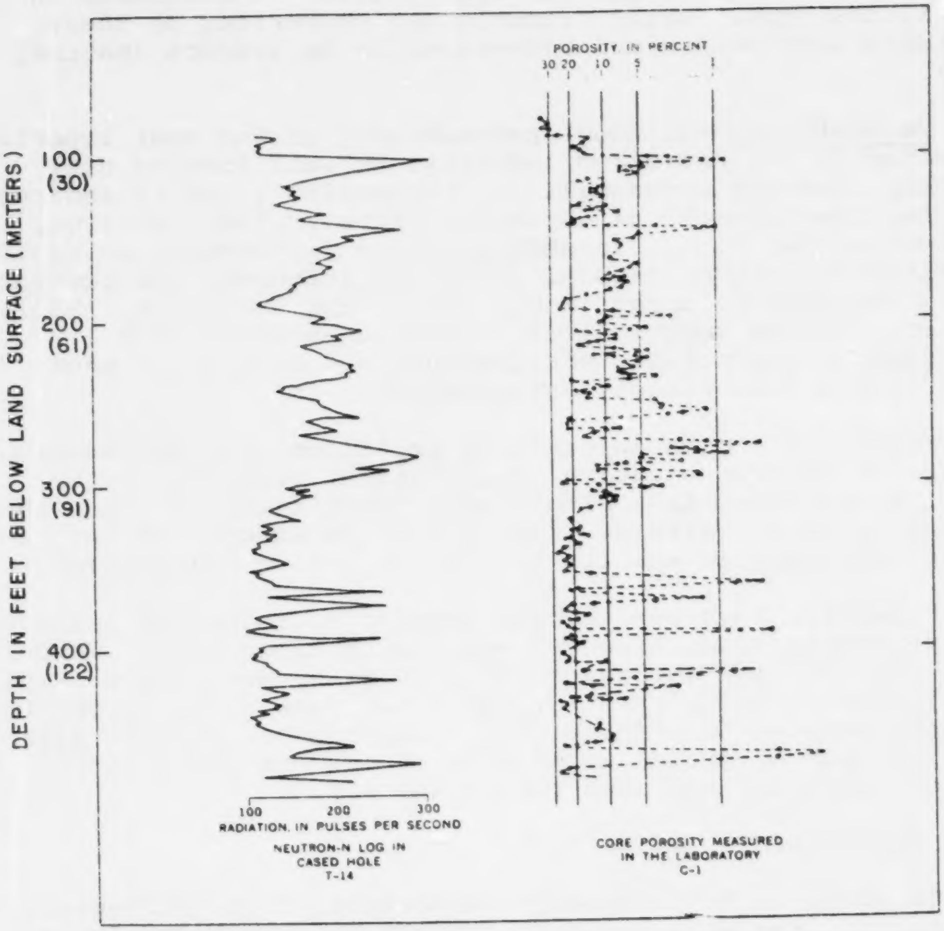

Figure 4.6 A comparison of a neutron log with porosity of core samples, Upper Brazos River Basin, Texas. (Keys and MacCary, 1973)

porosity because this log detects nearly closed fractures intersecting the borehole which are not delineated by other logs (Keys and MacCary, 1971).

Siple (1964) describes the use of acoustic velocity and caliper logs to determine the distribution of fractures in crystalline rock. Water transmitting properties of these fractures were determined between wells by tracers (Marine, 1966).

Permeability--Although permeability is the most important parameter in the petroleum industry, no well logging tool directly measures permeability. Permeability can be indirectly measured from electrical (Ershaghi, et al. 1978), neutron, and specialized logs. In sedimentary environments, an empirical relationship between natural gamma log intensity and permeability exists in specific areas (Rabe, 1957; Gaur and Singh, 1965). However, derived empirical relations can only be used in consistent geohydrologic environments and only after their relationship has been clearly established.

Keys (1967) uses injectivity profiling with radioactive tracers to measure relative magnitudes of permeability by plotting the water lost within each depth interval under the imposed hydraulic stress. Fig. 4.7 is an example of such an injectivity profile and its relationship to a caliper log.

Flowmeter logs used during pumping or injection indicate most permeable zones based on water acceptance rate. Temperature logs can also delineate zones of water acceptance (Keys and Brown, 1973). Velocity of ground water flow is an important property related to permeability. Logging can provide rate and direction of ground water flow if tracers are injected into one well and searched for in another.

Fluid Parameters--

In addition to lithologic parameters, fluid parameters can be obtained from well log data. These include formation and borehole water quality, location of brine-fresh water interface, fluid temperature, regional ground water flow patterns, and fluid movement within the borehole.

Water Quality--At any given temperature, the TDS content of waters with predominantly sodium chloride character is directly proportional to fluid resistance or conductivity. If other ions are present, in some instances multiplying factors may be used for conversion to electrically equivalent sodium chloride concentrations. Because of this relationship, electric logs provide data on water quality in uncased or fiberglass cased holes.

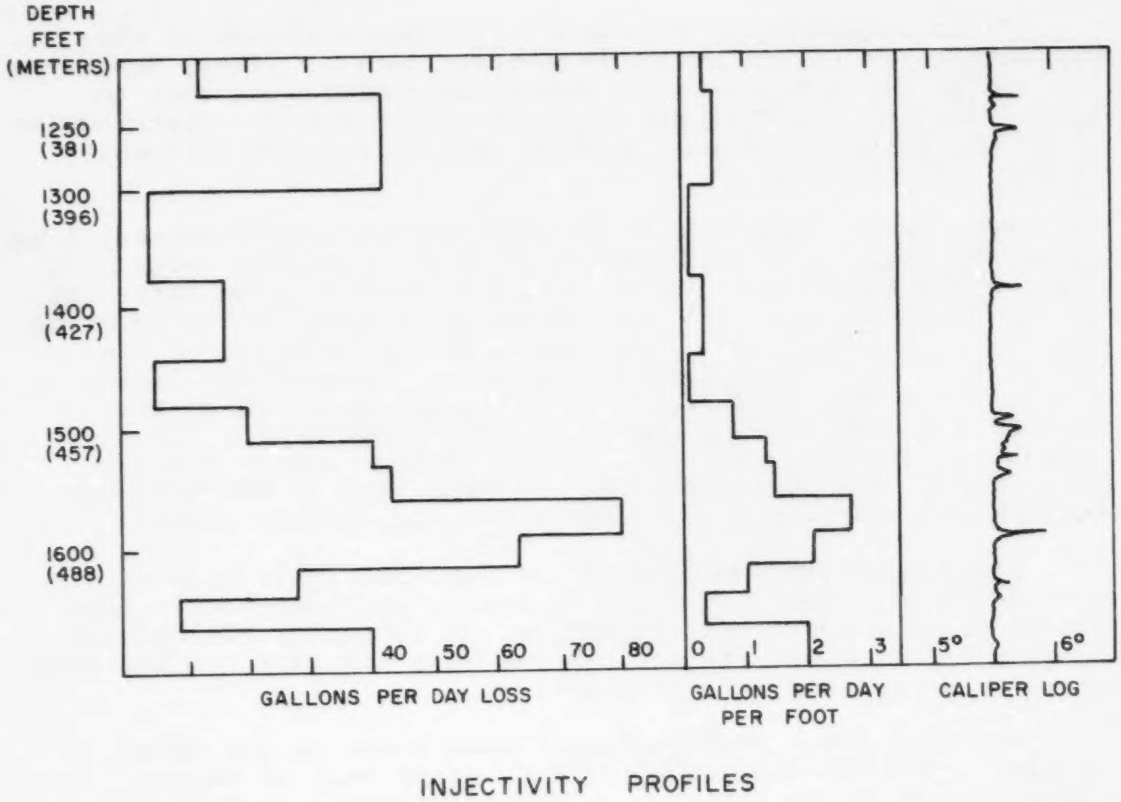

Figure 4.7 Injectivity profiles and their relation to a caliper log. (Keys and MacCary, 1971)

In cased and uncased holes, neutron logs give chlorine density and correspondingly relative water quality. Pulsed neutron logs are also sensitive to quantities of boron, lithium and silica in formation waters. Neutron activation logs give a qualitative technique for identifying several elements easily activated by thermal-neutron capture such as chloride, aluminum, silica, magnesium, potassium, manganese and sodium (Keys and McCary, 1971) and can indicate relative water quality in known lithologies.

Fluid conductivity logs are a continuous record of the conductivity of fluid in the borehole. Olmsted (1962) describes the use of fluid conductivity and fluid temperature logs to establish ground water flow patterns and to map the distribution of ground water types and injected wastes from the National Reactor Testing Station, Idaho.

Keys and MacCary (1973) demonstrate the use of several logs to locate changes in TDS concentration of formation water with depth. The right-hand log in Fig. 4.8 shows a large deflection in the fluid conductivity log caused by changes in the chemical quality of the borehole fluid, which is the location of the brine-fresh water interface in the well. Because the fluid conductivity tool only responds to the borehole fluid, the interface in the rocks might be at some other depth. In this situation, however, the shift on the neutron log on the left side of Fig. 4.8 indicates that the interface in the borehole corresponds with the actual one in the surrounding rocks.

Fluid Movement--Horizontal and vertical fluid flow within a well can be defined by using flowmeter and temperature logs and by various systems of injecting and detecting radioactive or chemical tracers. These logs can also indicate the horizons of water acceptance during injection.

Vertical flow in wells complicates sampling for water quality. Without knowledge of flow, water samples may be taken from stagnant zones or at depth intervals that do not represent water quality in adjacent aquifers.

Techniques for measuring natural or induced vertical movement of borehole fluids have been widely used in both the petroleum and ground water wells. Flowmeter logs provide continuous records of fluid velocities. Temperature and flowmeter logs can establish entrance and exit zones of water in the well. Repeated in several wells, areal patterns of ground water flow can be established.

Single well tracer techniques employ various tracers injected into a column of water and their movement to a detector is timed. Investigations with radioactive tracer techniques

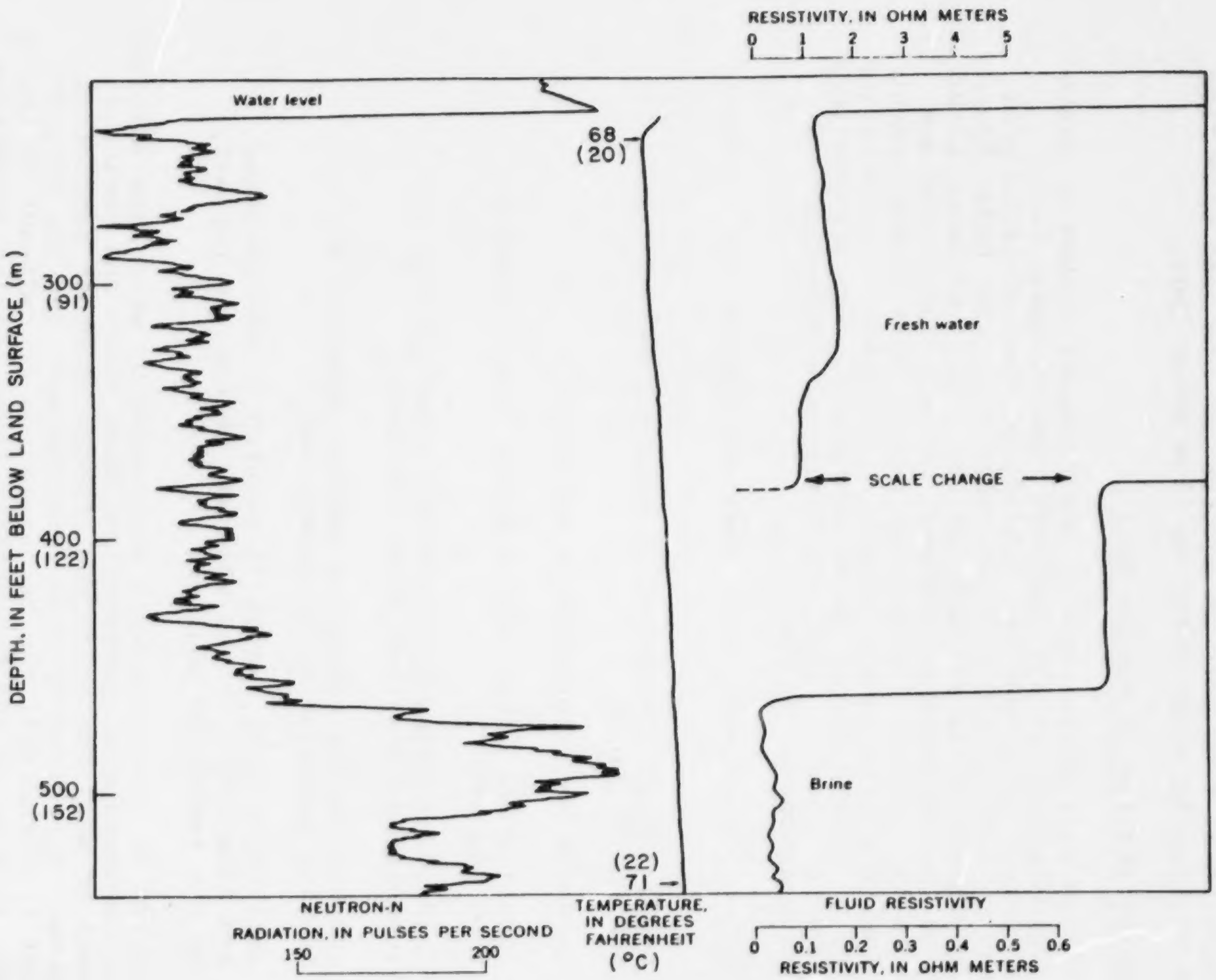

Figure 4.8 Location of brine-fresh water interface on neutron and fluid conductivity logs, hole T-19, Upper Brazos River Basin, Texas. (Keys and MacCary, 1973)

showed upward and downward flow in the same monitoring well, the changes of whole flow pattern being induced from injection and pumping rates in nearby wells (Barraclough, et al. 1965). Several radioactive tracer techniques including point dilution, single-well pulse, and use of directional detector are discussed by Keys and MacCary, 1971. These logs can record depth and flow rate of horizontal flow into an aquifer and are used when flow rates are too low to be measured by flow meter logs.

4.3.3 Monitoring the Injection Well

Injection well monitoring is the foremost method of waste injection monitoring, as the greatest risk of waste fluid escape is through or around the outside of the injection well rather than by leakage through permeable confining beds, fractures or unplugged wells (Talbot, 1972). Fluid movement takes place behind the casing when the seal between the casing and formation fails. Cement failure can result from a poor cement job, fracturing of the cement sheath at the time of perforation, or cracking of cement due to earth movements. The applications of well logs to injection well monitoring are summarized in Table 4.7 and discussed below.

At the injection well, well logs can monitor such factors as:

1) condition of the injection tubing, well casing and cement bond;

2) pressure and flow rate of injection;

3) location and direction of waste fluid movement from the well;

4) relative changes in formation water quality and temperature profiles along the well;

5) changes in the receiving aquifer porosity due to aquifer solution or plugging; and

6) well efficiency, which is related to the pressure and flow rates in the well and changes in porosity of the receiving aquifer.

A program of injection well monitoring by well logs involves continuous monitoring of pressure and flow rates and periodic measurements of well condition and changes in other parameters listed above. Direction of flow from the well and the location of movement from the well can be determined by radioactive tracer techniques, flow meter and temperature logs. Casing inspection, sonic, and to a lesser extent caliper, and borehole televiewer logs can determine the condition of tubing and casing, noting areas of corrosion. Cement bond logs are essential to determine the condition of the cement bond in the well. Fig. 4.9 shows a hole in the casing, located by casing caliper and casing inspection logs.

Leakage from the well cannot always be noted by injection pressure drops (increased well efficiency) or evidence from cement bond or casing inspection logs. Radioactive tracer techniques and temperature logs can be used to locate zones of fluid flow behind the casing and may be the only way of detecting whether annular leakage is or is not occurring from the well (Keys and Brown, 1973). Leakage from the well or movement of formation waters from one zone to another over a period of time can cause precipitation of radioactive minerals resulting in an interval of high radioactivity behind the casing. This anomaly can be picked up by comparison of recent and old gamma-ray logs. Relative changes in formation water quality, such as an increase in chloride, silica, boron or lithium content may also be evidence of leakage from the injection well. Relative changes in pulsed neutron, neutron activation, or electric logs can indicate these possible changes in water quality. Formation tester tools can also be used to determine water quality by recovering samples of formation water through the casing which are then chemically analyzed.

Changes in injection pressures can also imply solution or plugging in the receiving aquifer. Gamma-gamma logs can identify zones of hole enlargement behind the casing and pulsed neutron and neutron activation logs may indicate areas of silica precipitation. Neutron logs and other porosity indicators can reveal plugging of the aquifer.

Knowledge of post-injection fracturing is important to monitor the response of the aquifer to injection. Periodic inspections with sonic logs can indicate changes in the elastic properties of reservoir rocks, and indicate conditions that could cause fracturing.

At the Rocky Mountain Arsenal well, thermal differential stress is postulated to be a triggering mechanism contributing to microfracturing of the rock matrix and induced seismic activity (Hoover and Dietrich, 1969). Temperature control of injected geothermal wastewater in El Salvador also controlled silica precipitation problems. Hence, temperature logs are an important tool in maintaining favorable conditions in the injection well.

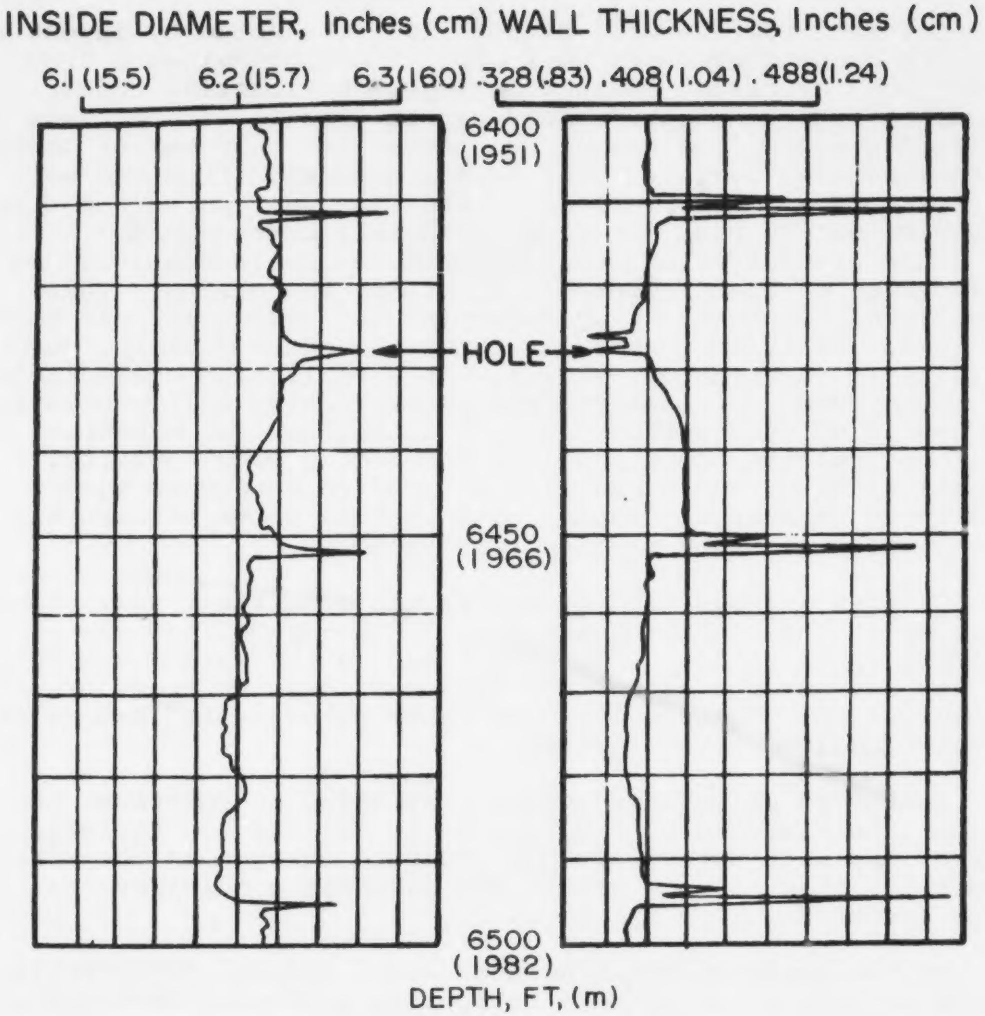

Figure 4.9 Typical simultaneous electronic casing caliper and casing inspection logs run in 7-inch casing. (U.S. EPA, 1977)

4.3.4 Monitoring Observation Wells

U.S. EPA (1975, 1977) proposes at least three different types of monitoring wells and pertinent data to be collected from each. The objectives and useful well logging tools for monitoring at these three types of observation wells are summarized in Table 4.8 and discussed below.

Observation wells are constructed where wastewater is expected to appear first if there is leakage from the injection horizon. Temperature and resistivity logs can be useful in mapping wastewater fronts if the injected water is of a different temperature and TDS concentration than the regional ground water system. At the National Reactor Testing Station, temperature and fluid resistivity logs were used to map the distribution from a deep disposal well (Fig. 4.10 and 4.11). Tracer techniques may also be employed to map wastewater movement if the tracer is introduced into the injection well and monitored at observation wells.

Observation wells constructed in or just above confining units of the injection horizon may be used to detect leakage through the unit by temperature and water quality logs and tracer techniques.

Observation wells constructed in the injection zone, can monitor pressure in the receiving unit and, depending on well location, direction of wastewater flow may be deduced.

In observation well construction, it is possible to leave the bottom few meters of the hole uncased or cased with plastic or fiberglass. In this way, electric well logging tools may be used, as well as pulsed neutron and neutron activation logs to monitor changes in regional water quality and map wastewater fronts or plumes.

4.4 WELL LOGGING COSTS

Certain well logs must be run by a well service company and others can be run by the geothermal developer. For collection of baseline data, running as many logs as economically possible ensures the most accurate interpretation of rock and fluid properties. In this instance, the service of a well logging company will be required. However, for routine monitoring, the logging tools may be purchased, thereby reducing expenses. These tools would consist of those used most frequently for monitoring, such as those for temperature, flow meter and pressure logs. Periodic monitoring of the condition of the injection well, which requires more sophisticated and varied equipment, usually will be performed by well service companies.

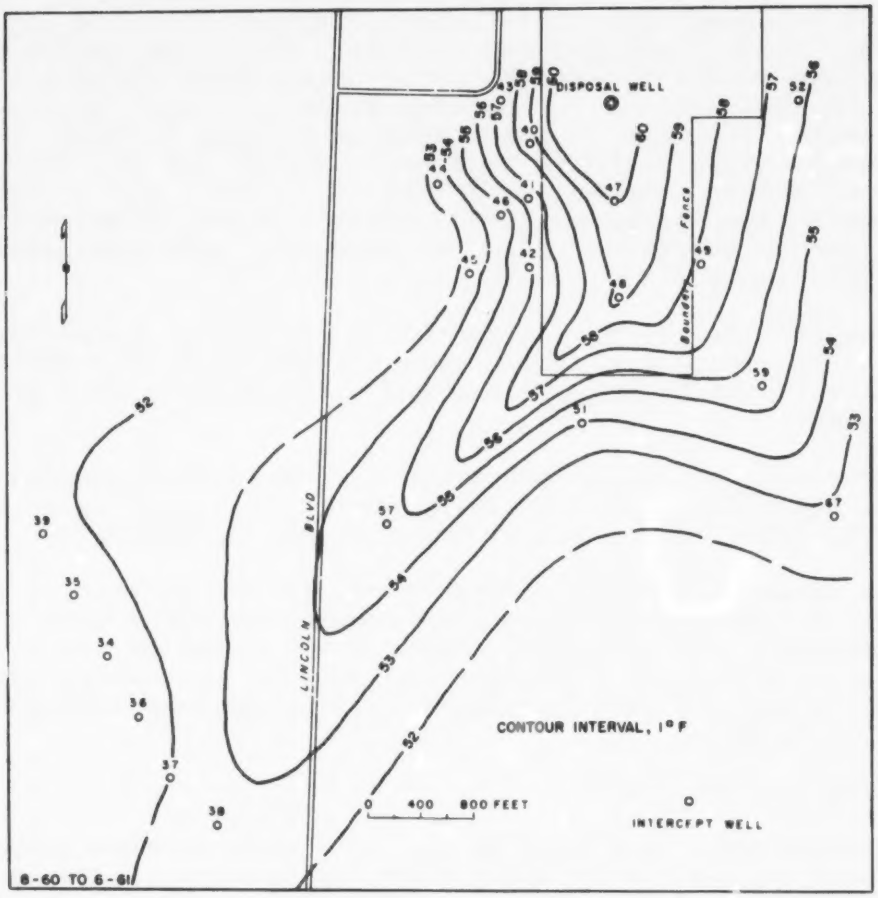
DISPOSAL WELL
Fence
Boundary
LINCOLN BLVD
CONTOUR INTERVAL, 1° F
0 400 800 FEET
INTERCEPT WELL
8-60 TO 6-61
52
53
54
55
56
57
58
59
60

Figure 4.10 Maximum temperature of water between depths of 140 to 200 m (459 to 656 ft) based on well logs of monitoring wells near a disposal well, National Reactor Testing Station, Idaho. (Jones, 1961b)

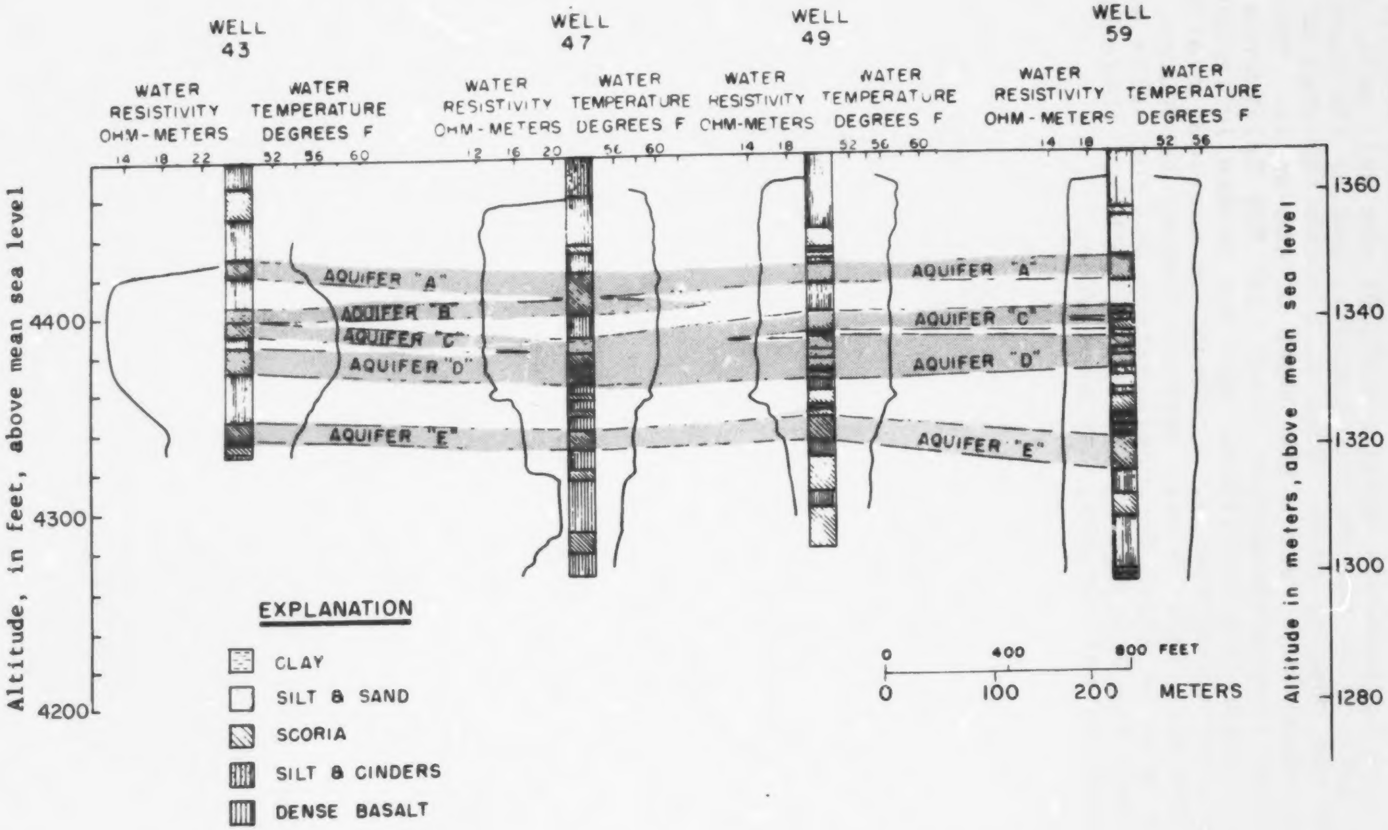
WELL 43
WATER RESISTIVITY OHM-METERS
14 18 22
WATER TEMPERATURE DEGREES F
52 56 60
WELL 47
WATER RESISTIVITY OHM-METERS
12 16 20
WATER TEMPERATURE DEGREES F
56 60
WELL 49
WATER RESISTIVITY OHM-METERS
14 18
WATER TEMPERATURE DEGREES F
52 56 60
WELL 59
WATER RESISTIVITY OHM-METERS
14 18
WATER TEMPERATURE DEGREES F
52 56
AQUIFER "A"
AQUIFER "B"
AQUIFER "C"
AQUIFER "D"
AQUIFER "E"
Altitude, in feet, above mean sea level
4400
4300
4200
Altitude in meters, above mean sea level
1360
1340
1320
1300
1280
EXPLANATION
CLAY
SILT & SAND
SCORIA
SILT & CINDERS
DENSE BASALT
0 400 800 FEET
0 100 200 METERS

Figure 4.11 Cross section through part of National Reactor Testing Station, Idaho, showing decrease in temperature and increase in resistivity of water with distance from the disposal well, which is nearest Well 43. (Jones, 1961b)

The cost of well logging by well service companies depends on: 1) the depth of the well, 2) the borehole condition (e.g. unusual or high temperature conditions), 3) the well site province as defined by the service company, and 4) the roundtrip mileage from the company base. Fig. 4.12 shows the cost of running individual logs versus the depth of the wells. These costs are taken from Schlumberger Price List for California Lands, 1978. Costs for individual logs are generally reduced when logs are run concurrently. Combination services available and prices are described in well service company brochures. Charges must also be added for mobilization and for wells with high bottomhole temperatures (over 150°C [300°F]). These costs must be determined individually for each site.

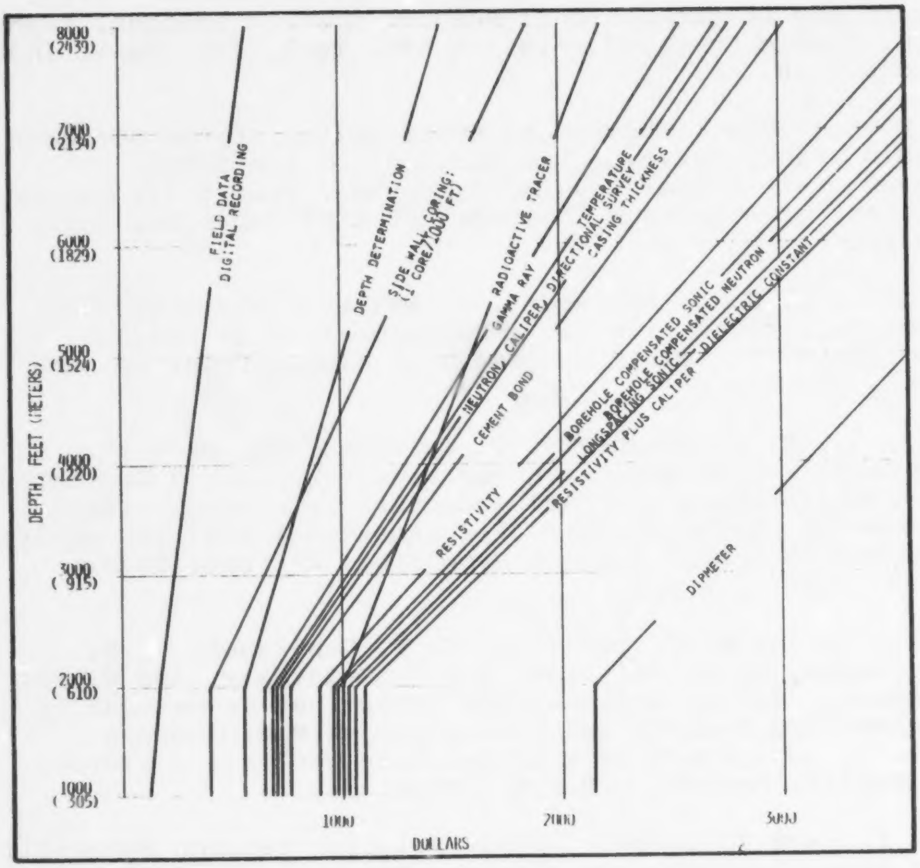

Figure 4.12 Well Logging Costs (Schlumberger, 1978)

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SECTION 5

GEOTHERMAL INJECTION TECHNOLOGY

Injection technology is an interdisciplinary field involving geology, hydrology, reservoir engineering, chemistry, materials science, mechanical engineering, well drilling, and completion technology. The state-of-the-art is a result of field experience as well as research and development in each of these areas of expertise. Although there is interdisciplinary cooperation, most studies for improving the technology concentrate on one area. However, in designing an injection system, it is important to combine applicable knowledge and experience from all areas.

Other methods of geothermal waste disposal have been conceived and some have been tried. Examples include: surface ponding at Cerro Prieto, Mexico; discharge to surface waters at Wairakei, New Zealand; ocean disposal in El Salvador. In most cases the quantity and chemical composition of the waste fluid make these alternatives environmentally unacceptable in the United States without prior treatment to remove the pollutants. The cost of such treatment may often be prohibitive.

5.1 DEVELOPMENT OF INJECTION TECHNOLOGY

Injection is a common secondary recovery technique in the petroleum industry. It is also used to dispose of industrial, domestic, municipal and nuclear waste. About 90,000 secondary injection wells and 30,000 disposal wells are believed to exist in the U.S. (National Water Well Association, 1978). Much of this nongeothermal injection technology can be applied to the geothermal industry including pretreatment methods, delivery system design, well design, control of chemical problems, redevelopment techniques, monitoring methods, and reservoir models. The petroleum and industrial waste disposal industries have provided the most significant contributions to geothermal injection technology. These are summarized below.

5.1.1 Injection in the Petroleum Industry

For the last 50 or 60 years, oil field brines have been injected into subsurface formations and today petroleum waste disposal is almost exclusively by injection. Brine injection wells are deep to avoid contaminating fresh water aquifers, and to increase the gravity head thereby decreasing pumping costs.

The waste may be injected into formations above or below the oil zone. Many fields inject into the oil-producing formation to displace the crude oil and increase recovery and economic gain. This secondary recovery method is called water flooding and the waste is generally supplemented with brine from formations other than the producing zone. Water flooding may increase oil recovery by 20 to 50% (Sanyal, pers. comm., 1978).

Injection volumes vary from field to field. In the largest known oil field in the U.S., the East Texas field, about 80,000 cu m/day (500,000 bbl/day) was being injected into 84 wells in 1972 (McWilliams, 1972). Injection volumes for other fields or wells are not readily available.

The chemistry of oil field brines is highly variable. Concentrations of total dissolved solids range from less than 100 to more than 100,000 ppm. Sodium or calcium chlorides are the major constituents of most brines, but magnesium, bicarbonate and sulfate predominate in some. Many other minor constituents and trace elements can be present, complicating the chemical properties of the fluids.

The most common chemical problems in petroleum field injection are precipitation, scale deposition, corrosion, and formation plugging due to chemical precipitation and/or bacterial growth. Techniques to control these problems include coagulation, chemical precipitation and corrosion control; pH fixation; chemical removal of silica, iron and manganese; mechanical sedimentation; filtration; aeration; addition of bactericide; and well stimulation. Reports by Collins (1975), Donaldson, et al. (1972) and Taylor, et al. (1939) describe some of these methods.

5.1.2 Industrial Waste Injection

Because of the increased attention paid to surface water pollution control since the early 1960s, injection of industrial waste has become widely used. Prior to 1960, only 22 industrial waste disposal wells had been constructed. As of 1974, the total was 322, of which 209 were operating.

Of the wells constructed by 1973, 94% were in sand, sandstone and/or carbonate rocks. About 20% utilized only gravity flow for injection pressure; the rest were assisted by pumping with wellhead pressures up to 10.3 MPa (1500 psi). Most industrial injection wells are between 300 and 1800 m (1000 and 6000 ft) deep.

As of 1975, a total of 114,000 cu m (30 million gal) of industrial waste was being injected per day into disposal wells. This is about 0.08% of the total industrial liquid waste discharge of the U.S. (Reeder, et al. 1977).

5.2 CHARACTERISTICS OF GEOTHERMAL INJECTION

Subsurface injection of geothermal effluent is a special case of deep well injection. Unique characteristics of geothermal effluent injection are the chemistry, temperature and quantity of the fluid being injected, the injection depth, reservoir rock type and the flow dynamics of the system. These five characteristics are discussed below.

5.2.1 Chemical Characteristics

Two aspects of the chemical composition of the fluid are particularly meaningful to the subject of injection. First, the high salinity and other trace minerals may degrade the fluid in usable aquifers, and second, certain constituents may contribute to scaling or corrosion of the injection well, or plugging of the receiving formation. Substances found in geothermal fluids that tend to form scale are carbonate, silica, calcium, metals and sulfate. Corrosive agents found in geothermal fluids are chloride, oxygen, and the acidic nature of some fluids.

A third aspect, not quite as important as the first two, is the variation of the specific gravity of the fluid with TDS (Fig. 5.1). Since the composition of the fluid varies within the reservoir and the well and with time, these density differences may induce a density current component on the flow system.

Knowledge of the chemical composition of geothermal fluids can provide much useful information about the reservoir, since the kinds and amounts of constituents depend on the reservoir environment: formation lithology, rock-water interaction, rock-mineral-chemical equilibria, pressure and temperature. The geographical variation in chemical characteristics may be attributed mainly to variation in the nature of the subsurface rocks, temperature, and distance from the source of recharge. Temporal variation in the chemistry of geothermal fluids at a particular site can have a number of causes, the most important being the variation in the rate of fluid recharge (natural or artificial) into the reservoir.

5.2.2 Temperature

Geothermal fluid temperature in deep well disposal involves the temperatures of two distinct fluids, the injected fluid and the resident reservoir fluid. Depending on the power conversion

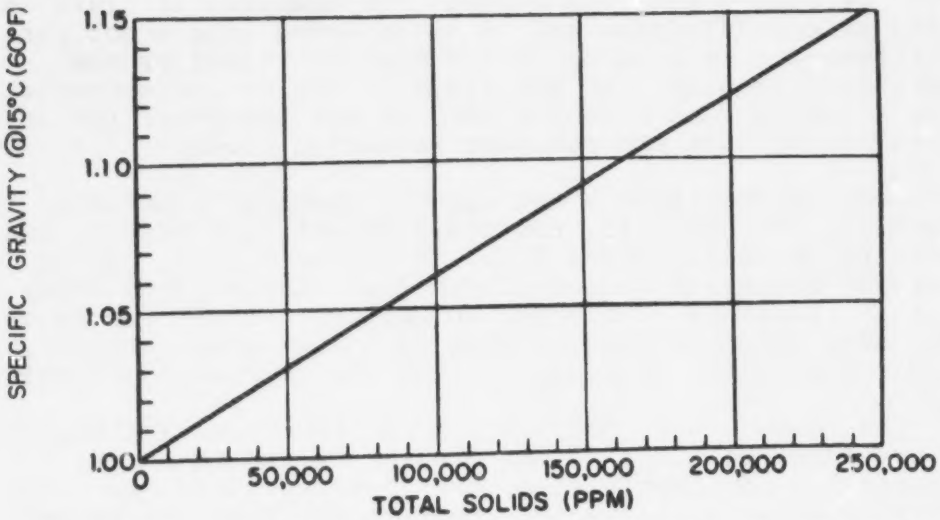

Figure 5.1 Specific gravity of sodium chloride formation waters versus total solids in ppm (Warner, 1975, from Pirson, 1963, p. 39)

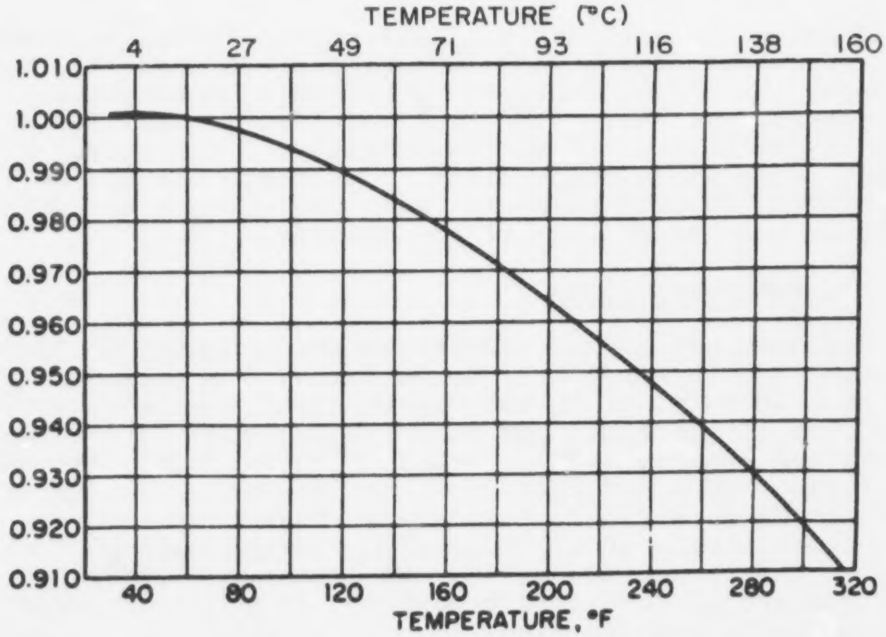

Figure 5.2 Specific gravity of distilled water as a function of temperature (Warner and Lehr, 1977, from Pirson, 1963, p. 39).

and disposal well facilities either of these fluids could be hotter or colder than the other. For example, if fluid is cooled before injection and it is injected into a hot part of the reservoir, it will be cooler than the fluid or the receiving formation. If the fluid is not cooled appreciably and it is injected into a cooler part of the reservoir the injectate may be hotter than the resident formation fluid.

Temperature affects the rate of chemical reactions, the solubility of materials, the fluid density and volume, and the viscosity of the injected fluid in the well bore, casing, and receiving formation. Generally higher temperatures imply faster chemical reactions, increased solubility (except for calcium carbonate, which is less soluble at higher temperatures), decreased density, increased volume and decreased viscosity.

The temperature contrast between the receiving formation and the injected fluid is important. Depending on the relative temperatures and chemistries, the injected fluid may form precipitates or may dissolve constituents from the formation or formation fluid. These chemical reactions must be critically evaluated in planning the disposal well system. In addition, the temperature contrast will generate density currents which will affect the flow patterns. Fig. 5.2 shows the change of specific gravity with temperature in distilled water.

Changes in viscosity will affect the hydraulic conductivity of the receiving formation. Higher temperatures will lower the viscosity thereby increasing the hydraulic conductivity; lower temperatures will have the opposite effect. Fig. 5.3 shows water viscosity as a function of temperature and salinity. A 100°C (212°F) temperature differential can change the hydraulic conductivity by 300% or more. This will have a significant effect on the receptivity of the aquifer.

5.2.3 Quantity of Fluid

For most geothermal operations the quantity of fluid processed and injected will be enormous. For example, in operation of a 10 MW plant in the Otake, Japan fields 1,230,000 kg (2,700,000 lb) of fluid per hour are injected into three wells (Kubota and Aosaki, 1976) at rates of 4.69, 6.06 and 9.08 cu m/min (1,240, 1,600 and 2,400 gpm) in each well. At the steam-dominated Geysers field, California, injection into six wells at an average rate of 2.1 cu m/min (550 gpm) per well is taking place in the production of 502 MWe (Chasteen, 1976, p. 1335). Large commercial levels of production in a hydrothermal resource would probably require significantly greater injection.
For example, in a feasibility study for a 25 to 50 MWe geothermal power plant, a hypothetical production scheme outlines utilizing an array of 36 wells producing 0.063 cu m/sec (1,000 gpm) and 18

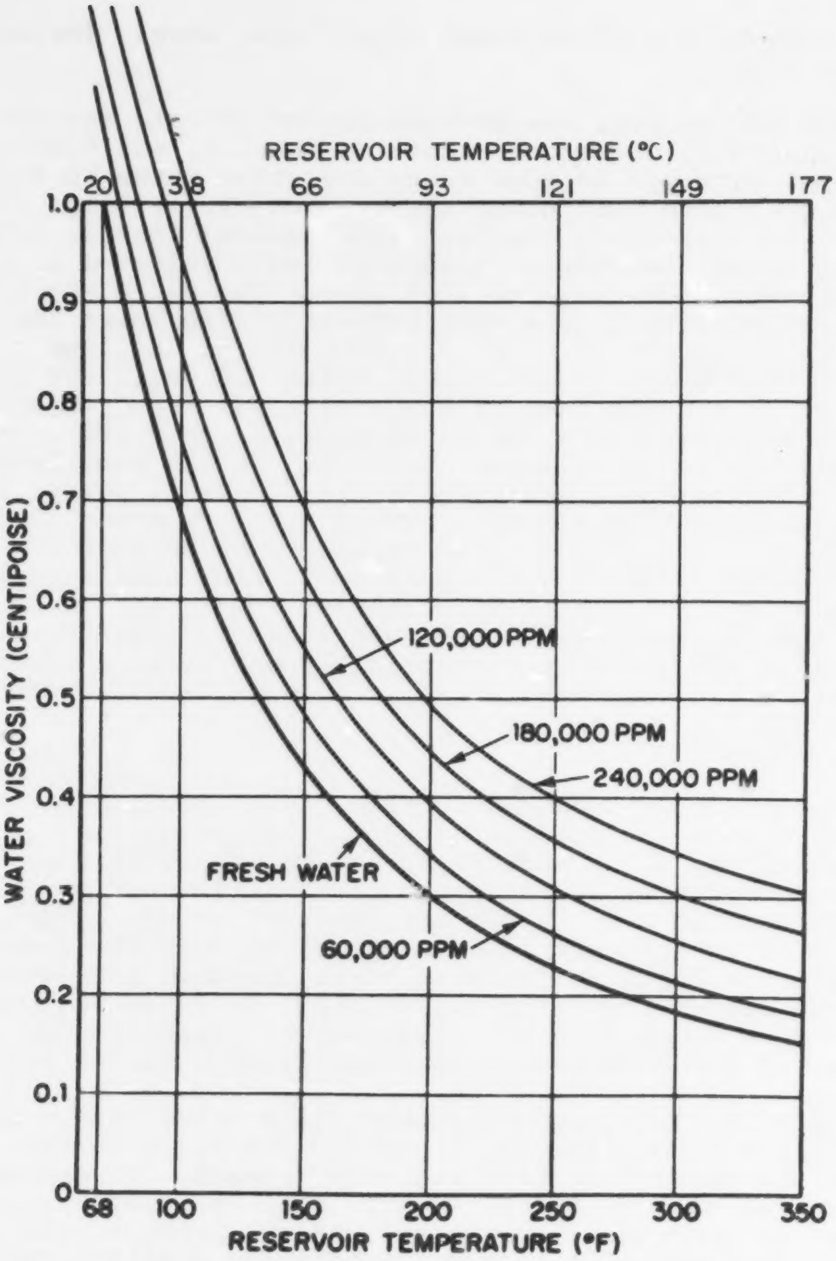

Figure 5.3 Water viscosity as a function of temperature and salinity (equivalent ppm NaCl) (Warner & Lehr, 1977, from Pirson, 1963, p. 40)

wells injecting 0.13 cu m/sec (2,000 gpm) each. (Meidav and Sanyal, 1976).

For comparison, the average injection rate for 209 operating wells disposing hazardous wastes in the U.S. was 0.063 cu m/sec (100 gpm) although in some cases injection rates to 0.12 cu m/sec (1,900 gpm) have been noted (Reeder, et al. 1977, p. 106 and 1050). Another study (Warner, 1972) showed that in 1967 one percent of all industrial injection wells injected at a rate greater than 0.05 cu m/sec (800 gpm). The petroleum industry has commonly injected brines into petroleum reservoirs for secondary recovery of petroleum. For example, in the Hastings oil field, Brazoria and Galveston Counties, Texas, 25 wells are injecting brine at an average rate of 0.004 cu m/sec (64 gpm) per well for a total injection into the field of 7,900 to 9,500 cu m/day (2.1 million to 2.5 million gal/day). In the East Texas oil field, Upshun, Gregg, Rusk and Smith Counties, Texas, 84 wells are injecting at an average rate of 0.011 cu m/sec (174 gpm) per well (McWilliams, 1972). The total injection into the field is 80,000 cu m/day (21,000,000 gal/day). The quantities to be injected from full-scale hydrothermal power production will be significantly greater. These quantities of fluid production and injection will stress the existing ground water regimes to a much greater extent than most existing injection well systems.

5.2.4 Depth

Injection will generally take place within the geothermal reservoir or at an equivalent depth. Although the tops of some reservoirs may be as shallow as 0.3 km (1,000 ft), as in Steamboat Springs, Nevada, most reservoirs upper boundaries are deeper than 1 km (3,000 ft) (Renner, et al. 1975). However, the top of the reservoir would establish only the upper limit of injection depth and in most cases geothermal injection wells would be deeper than 1 km (3,000 ft). Juul-Dam and Dunlap (1976) report a mean depth to the reservoir of slightly over 1,520 m (5,000 ft) and a median depth under 1,830 m (6,000 ft) (Fig. 5.4).

Ideally, injection will take place below one or several impermeable layers that will confine the fluid to the injection depths and prevent it from migrating upward. In sedimentary reservoirs, such as in the Imperial Valley, these confining layers consist of impermeable clays and shales, perhaps with the self-sealing features of silica or carbonate deposition forming a reservoir caprock. In fractured igneous reservoirs this confining layer would most probably consist of silica caprock deposited by the self-sealing mechanism of the geothermal system.

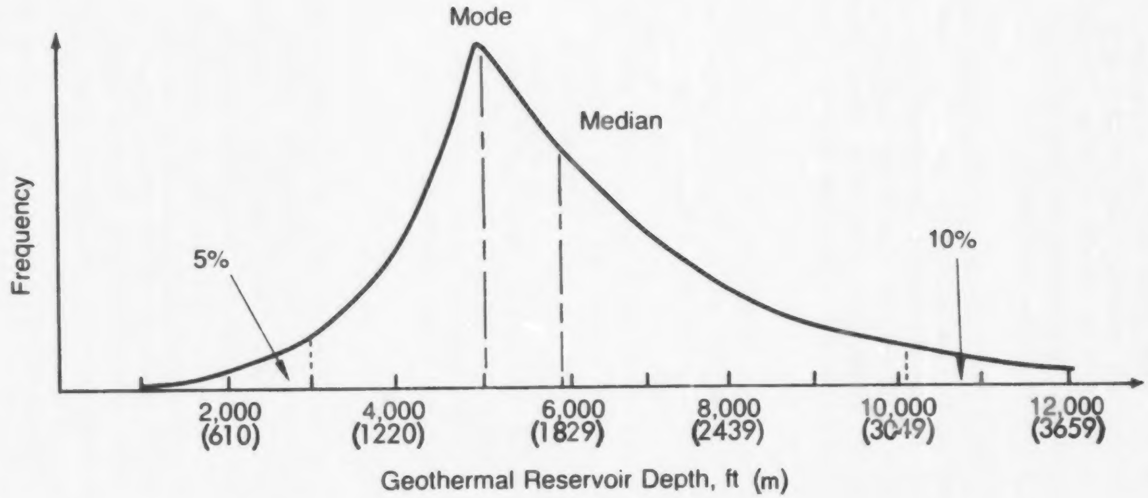

Figure 5.4 Geothermal reservoir depth distribution. (Juul-Dam and Dunlap, 1976)

5.2.5 Flow Dynamics

The flow dynamics of a geothermal injection system will be different than those of most deep well disposal systems. This difference is manifested by the combination of fluid injection and extraction in the geothermal reservoir. In most disposal well systems fluid is merely injected and left to migrate solely under the pressure head of the injected fluid. The pumping of the geothermal production wells will provide additional stimulation to the flow network.

Injection to stimulate petroleum production--as opposed to injection for waste disposal--is similar to the geothermal waste injection. Also similar to geothermal extraction-injection are the ground water barriers formed by doublet injection-extraction well pairs. An example of this process has been described in a study done by Stanford University for the Santa Clara Water District (Sheahan, 1977).

One must acknowledge that extraction and injection of fluid for geothermal energy production will superimpose additional forces on an existing dynamic ground water flow system. Although hydraulic conductivity between the geothermal reservoir and overlying ground water aquifers will be poor, the additional forces of production and injection may have some effect on the gradients of overlying aquifers or may cause fluid to escape from a previously confined reservoir. In planning an injection well system, these possible effects must be recognized. Mathematical models may help establish the effects of different combinations of injection and production rates at different locations and depths on the overall ground water flow.

5.2.6 Reservoir Rock Type

Most hazardous waste injection wells in the United States are completed in sedimentary strata, largely sands, sandstones and carbonates (Warner and Lehr, 1977, p. 6). The numerous brine injection wells used in the petroleum industry are also completed in sedimentary strata, mostly with intergranular porosity. Because geothermal reservoirs tend to occur in igneous or metamorphic rock masses with fracture permeability, the flow mechanism and well performance characteristics for geothermal injection and production wells differ from those for most nongeothermal wells. The extent of these differences will depend on the type and degree of fracturing in the aquifer. A rock mass with a dense network of small open fractures may behave like one with intergranular permeability. On the other hand, an aquifer which carries the greatest part of its water through a few major fractures will have quite different characteristics.

5.3 GEOLOGIC, HYDROLOGIC AND RESERVOIR EVALUATION

The physical aspects of the geothermal reservoir and its geologic and hydrologic surroundings must be known in order to conduct a safe and effective geothermal injection program. The necessary geologic and hydrologic data would include: 1) descriptions of the geologic structure and stratigraphy (including maps and cross sections), 2) locations, thicknesses, depths and areal extents of aquifers, 3) transmissivities of aquifers, 4) water table depths and elevations, 5) piezometric surfaces, 6) recharge and discharge areas, and 7) rate and direction of natural ground water flow. Details of these data and their collection are outlined in the first two steps of the monitoring methodology (Sections 3.1 and 3.2).

Reservoir development data must be superimposed on the existing flow regime. Some hypothetical examples of this are outlined in Section 2.4 on geothermal reservoir engineering.

Since geothermal fluid is injected not only as a means of waste disposal but also to maintain reservoir pressure and reduce subsidence potential, the fluid may be injected into the production zone. Hydraulic confinement to this interval must be maintained to prevent upward migration of the fluid and possible contamination of overlying aquifers. In sedimentary reservoirs, such as in the Imperial Valley, the confining layers are impervious clays and shales. In fractured igneous reservoirs, the confining layer may be formed by the self-sealing mechanism of geothermal systems. This mechanism involves deposition of a silica caprock at a depth where the temperature and pressure of the rising silica-saturated geothermal fluid are low enough for the silica to precipitate in the fractures and seal off the reservoir (Facca, 1973). In some systems the mechanism may be somewhat different and involve deposition of carbonate or other minerals.

5.4 CHEMICAL PROBLEMS

Certain chemical characteristics of geothermal production-injection systems may create problems such as scale deposition in the injection lines and well bore, plugging of the formation around the well, and corrosion of pipes in the system. High temperatures and pressures, as well as injecting water mixed from different production wells, add to the complexity of the chemical problems. These problems and their solutions are discussed in this section.

5.4.1 Scaling

Injectivity can be severely decreased by scale and precipitates which accumulate in the well bore, in and around the slotted liner, and in the injection formation. Plant process conditions, such as temperature changes, pressure reduction, the type of materials in contact with the fluid, and the contact duration, affect scale deposition rates. The reactivity of different surfaces may vary with flow rate and temperature. Hence, different types and thicknesses of scale will result from flow over surfaces of different shapes and materials (Wahl and Yen, 1976). Table 5.1 lists some factors which affect scaling.

The following chemical mechanisms can deposit scale in injection systems:

1) polymerization and precipitation of silica and silicates;
2) precipitation of insoluble carbonates, sulfates and hydroxides of alkaline earths;
3) precipitation of heavy metal sulfides; and
4) precipitation of redox products.

Deposition of silica and calcium carbonate (calcite) are the most common scaling problems. Scale can be controlled by chemical or physical methods. Table 5.2 presents some scale prevention techniques and Table 5.3 presents scale removal methods. Silica and calcite scale are discussed below.

Silica Scale--

Since nearly all geothermal waters contain appreciable quantities of silica, the complexity of silicate chemistry has presented great problems in production technology as well as waste control technology. Neither the mechanism nor the kinetics of silica polymerization are adequately understood (Axtmann, 1976).

The silica concentration of extracted geothermal fluids is equal to the solubility of quartz at the reservoir temperature. Therefore, the silica concentration may greatly exceed the solubility of amorphous silica (become supersaturated) at the lower injection temperatures leading to silica precipitation (silication). At Ahuachapan, for example, the reservoir temperature is 235 to 245°C (455 to 473°F) and the fluid cools to 98°C (208°F) at the surface. This temperature drop to the local boiling point results in silica supersaturation. Resultant precipitation and scaling are serious problems (Cuellar, 1976).

TABLE 5.1 FACTORS AFFECTING SCALING IN GEOTHERMAL PLANTS
(Modified from Phillips, et al. 1976)

Factor	Effect on Scaling
Fluid phase (steam or water)	More scale will be deposited from water than from steam; flashing can induce scale deposition.
Brine composition	Determines the type of scale.
Temperature and temperature changes	Variable effects depending on chemistry; lowering temperature induces silica scaling, rising temperature induces calcium carbonate scaling.
Pressure changes, including partial pressure change in CO_2, H_2S, NH_3	Causes change in solubility of materials.
Velocity and turbulence	Scale will tend to accumulate at places where fluid velocity changes; e.g. elbows, constrictions, valves.
Residence time in each part of plant	Longer residence time tends to increase degree of scaling.
Surface effects and surface to volume ratio effects	The higher the surface to volume ratio, the less scaling per unit area; scale will tend to accumulate on irregularities of the surfaces.
Geometry of plant components	Controls location of scaling, see "velocity and turbulence" comment above.

TABLE 5.2 TYPICAL PREINJECTION TREATMENT TECHNIQUES TO CONTROL SCALE FORMATION (Modified from Phillips, et al. 1976)

Scale Type	Control Technique	Location
Silica and calcite	pH adjustment (acid injection)	Magmamax No. 1 well, Niland, California
Silica	Injection of base (NH_3 or NaOH)	Sinclair wells, California
Silica	Dilution of the unflashed geothermal fluid	Namafjall, Iceland
Silica and arsenic	Sedimentation and coagulation (addition of slaked lime, hydrochlorite, and flocculant)	Wairakei and Broadlands, New Zealand
Silica	Plain sedimentation; retention tank	Otake, Japan, and Ahuachapan, El Salvador
Mixture of metal sulfides, carbonates and silicates	Application of electrical potential	Sinclair Well No. 4, California

TABLE 5.3 TYPICAL SCALE REMOVAL TECHNIQUES APPLICABLE TO INJECTION SYSTEMS (Modified from Phillips, et al. 1976)

Scale Type	Removal Technique	Location
$CaCO_3$ (calcite) in borehole	Pump inhibited HC1 into the well	East Mesa Well 5-1 and Otake, Japan
Calcite in bore	Reaming or redrilling	New Zealand, Hungary, and Mexico
Calcite in well casings	Wash with inhibited HCl	Hungary and Kawerau, New Zealand
Silica in flow control equipment and heat exchangers	Wash with ammonium bifluoride	Hveragerdi, Iceland
Silica in borehole	Pump NaOH solution into the well	Matsukawa, Japan
Mixed scales in injection and brine drain lines	Cavitation descaling	Niland Geothermal Test Facility, California

Polymerization is a process where large molecules are formed by the joining together of small molecules, e.g. formation of SiO_2 chains. Polymerization of silica apparently does not occur under extreme acidic or alkaline conditions. Dissolved monomeric silica is relatively stable between pH 2 and 3. Maximum polymerization has been reported at various pH's between 5.85 and 10. Silica becomes stable against polymerization at very high pH's, presumably due to the increased solubility of the silicate ion at these pH's (Axtmann, 1976). Increasing temperature and decreasing silica concentration lengthen the polymerization induction period of silica. The polymerization rate increases with temperature up to about 50°C (122°F), then decreases, perhaps due to mass transfer rates (Axtmann, 1976). Various ions and the pH of the solution can inhibit or catalyze silica polymerization (Iler, 1973).

Chemical control of silica scale--Chemical methods of silica scale control can be categorized into three types: 1) prevention or postponing of scaling by inhibiting polymerization; 2) deliberate precipitation of silica prior to injection; 3) chemical removal of the scale once it forms in the injection system.

Silica polymerization can be inhibited by:

1. keeping the temperature high enough to prevent silica saturation;
2. reducing turbulence, thereby avoiding increments in the velocity gradients and collision of particles which may increase pH;
3. lowering the pH of the solution below 6.5, which substantially decreases polymerization.

Silica-laden discharge waters have been successfully treated with slaked lime to precipitate silica as well as arsenic. This process has been tested at the Wairakei and Broadlands fields in New Zealand. Discharge water is contained in holding ponds to allow silica polymerization, then slaked lime is added. Hydrated calcium silicate gel precipitates and is separated in settling tanks and dried. The calcium silicate precipitate can be used in wallboards, insulants and perhaps in cement and ceramics. By controlling lime addition rates the calcium silicate can be made silica-rich or calcium-rich. (Rothbaum and Anderton, 1976). The discharge water depleted in silica can then be disposed of without silica deposition.

The water from the Otake geothermal field in Japan is ponded for about one hour, while formation of nonadhesive colloidal silica takes place. Once polymerization ceases the water can be handled without a serious silica scaling problem. (Yanagase, et al. 1970)

Application of a negative electrical potential has been found to reduce silica scaling for the Salton Sea geothermal brines (Phillips, et al. 1976).

While prevention of scaling can be achieved by proper treatment of the waste, it is also possible to chemically remove the scale once it is formed. Though insoluble in water and acid, silica turns to soluble silicate when treated with alkali or carbonate. In a production well plugged with silica scale at Matsukawa, Japan, 125 kg of NaOH dissolved in 300 liters of water was placed in the wellhead for 8 minutes, the wellhead was flushed with pure water for 15 minutes, and the process was repeated. Scale removal was complete. Siliceous scale (90% silica) has been successfully removed by treatment with a sodium hydroxide (NaOH) solution under high pressure and temperature. Use of NaOH has the disadvantage of precipitating metal hydroxides which can cause formation plugging (Ozawa and Fujii, 1970).

Of the scale prevention measures discussed above, deliberate precipitation and removal of silica prior to injection is probably the most certain means of control, as it decreases the poorly understood problem of silica plugging in the injected formation. Preventing precipitation under surface conditions may only delay deposition.

Calcite Scale--

Solubility of calcite is a function of CO_2 gas partial pressure, temperature, pH and other species in solution. Calcite precipitation may be controlled by controlling one or more of these factors. A decrease in pressure as geothermal fluid flows from the wellhead releases CO_2 which in turn favors formation of calcite. Monitoring a CO_2 backpressure could prevent this precipitation; however, the backpressure would also decrease the flow rate.

Various scale inhibitors (polyelectrolytes, ester of phosphoric acid, phosphorates, etc.) have been used to slow down the precipitation rate of calcium carbonate. A glassy phosphate called Calgon has been used to prevent scaling as well as to control corrosion.

To remove carbonate scale, acid solutions can be used. Calcite ($CaCO_3$) dissolves in hydrochloric acid according to the following reaction:

$$CaCO_3 + 2HCl \rightarrow Ca^{++} + H_2O + CO_2\uparrow + 2Cl^-$$

Acidizing has been used to remove scale from well casings in the Kawerau Field, New Zealand; Otake, Japan; and East Mesa, California. Caution must be used in dissolving calcite with acid since highly acid solutions may create unpredicted problematic chemical reactions when they enter the injected zone. Also, as the injected fluid moves into the receiving formation, dilution of the acid will decrease the solubility of $CaCO_3$, possibly resulting in formation plugging from $CaCO_3$ deposition.

Physical Removal of Scale--

Scale, particularly carbonate, can be removed by physical methods such as scraping or scratching the deposits from the inside of well walls, casings and pipelines. Water jets are also a potential method for removing scale.

In geothermal wells in New Zealand, Hungary and Mexico, calcite has been removed with scratchers or reamers. The rotary transverse motion of a reamer in the hole will remove deposits. This method is fairly expensive as it requires a drill rig and may shut the plant down for several days. Since only the bore is cleaned, deposits in casing perforations and in the formation remain, and cuttings from the reaming may get forced into casing perforations and block flow.

Scrapers can remove scale from pipelines. There are various types of scrapers--steel balls, chained rubber balls, plugs and wire brushes, "go-devils" and spiral-brush "pigs". They are inserted at inlet traps in a system and removed at outlet traps, scouring the pipe between. A problem with scrapers is that they can damage plastic lining of the pipes (Phillips, et al. 1976).

In cavitation descaling, pulsating high-pressure water jets are directed against scaled surfaces. The alternating pressures cause bubbles to form and collapse on the scaled surface. Collapse, or implosion, of these bubbles creates shock pressures up to several hundred atmospheres, which break the scale from the metal surface. At the Niland geothermal test facility, cavitation successfully removed scale from about 366 m (1,200 ft) of injection line.

5.4.2 Formation Plugging

When the injected fluid is mixed with formation water and reacts with minerals, precipitation can occur, plugging the formation.

Reaction Between Injected Fluid and Receiving Formation--

The reactions between injected acidic industrial wastes and receiving waters and minerals have been studied (Grubbs, 1972). The zone of reaction around geothermal injection wells is probably similar to that around industrial waste disposal wells; however, in geothermal projects, the injected fluid and formation fluid may differ much less chemically. A gradational boundary (zone of reaction) develops between the injected and the formation fluids. In this zone, some minerals will be dissolved or altered, metastable sols and gels will form and new compounds will precipitate. The extent of this zone will depend upon the length of time the fluid has been injected and its flow rate, the mixing rate of the injected fluid and formation water, and chemical reaction rates. Although chemical reactions may be predicted by laboratory mixing of the two fluids, the physical effect on the system is difficult to predict. A precipitate, for example, may cause immediate plugging of the formation, be flushed through the receiving formation without plugging it (especially if fracture permeability exists), or may slowly accumulate and gradually retard injection.

Silicates and carbonates are the most common cause of plugging in geothermal systems. Their deposition is by the same mechanisms as described for scaling, except that they are deposited in the voids of the formation rather than in the well casing.

Formation plugging can also be caused by swelling clays due to water formation incompatibility. This problem is restricted to sedimentary reservoirs.

Bacterial growth, which causes plugging around some nongeothermal injection wells should not be a problem in most geothermal injection wells. Few bacteria thrive in the high geothermal temperatures. Cool injected fluid from open systems might have bacterial contamination which could cause plugging.

If the fluid is not filtered prior to injection, particulate and colloidal matter can plug the formation.

Control of Plugging--

Plugging of the formation can be minimized by settling, filtering, and removing the solids and/or by adding inhibitors to prevent precipitation of the solids. Even then, downhole plugging is possible. Well stimulation techniques include acidizing and hydraulic fracturing. Shock treatment has also been used with some success. It involves subjecting the formation to an almost instantaneous applied pressure differential (implosion) and sustaining this pressure for a period, thereby loosening the obstructing material.

5.4.3 Corrosion

The complex chemistry of geothermal fluids impedes injection technology development. Each field, sometimes each well, has its own combination of corrosion mechanisms which must be defined and controlled. Experience with seawater corrosion provides a base for studying materials behavior in the similar, though generally much more corrosive, geothermal fluid. Marine experience includes studies of electrochemical potential of various metals, as well as the effects of dissolved oxygen, temperature and fluid velocities on corrosion mechanisms (La Que, 1975).

In geothermal fluids, the chloride ion (Cl^-) is generally considered the main corrosive, with hydrogen sulfide (H_2S) probably next in importance. Brine chemistry, pH, dissolved gases (such as oxygen, carbon dioxide, and ammonia), temperature, flow rate, well depth and pressure all affect corrosion, either individually or in combination. The types of metals used also influence the types and degree of corrosion in the system. Table 5.4 lists some of these factors.

Dissolved oxygen is important to corrosion. The ionization of oxygen,

$$O_2 + 2H_2O + 4e^- \rightarrow 4OH^-$$

is believed to be the principal cathodic process in the electrochemical action of geothermal fluids. It is the main cause of dissolution of metals such as steel and copper. On the other hand, oxygen is required to produce the oxide films which make many metals passive. Titanium, aluminum and stainless steel are corrosion-resistant only after the surface is oxidized. Other aspects of oxygen's role in corrosion remain unresolved.

The most common ways in which metals used in geothermal installations corrode are (1) uniform attack or general corrosion, (2) pitting and crevice corrosion, and (3) stress corrosion cracking. Corrosion fatigue and erosion cavitation are also observed in pumps. These types of corrosion are explained below.

Uniform attack or general corrosion refers to a regular, nondiscriminating chemical reaction on an entire surface. Examples of this type include rusting and other forms of oxidation.

Pitting and crevice attack can affect materials that are resistant to general corrosion. These local phenomena are

TABLE 5.4 FACTORS AFFECTING MATERIAL CORROSION IN GEOTHERMAL PLANTS (Modified from Phillips, et al. 1976)

Factor	Effect on Corrosion
Fluid phase (steam or water)	Affects the concentration of corrosive constituents.
Brine composition	Affects the type & rate of corrosion; more concentrated brines tend to be more corrosive.
pH of fluid	Extreme pH generally increases corrosion.
Temperature & temperature changes	Higher temperatures generally accelerate corrosion.
Partial pressures of CO_2, H_2S, NH_3, H_2	Increased gas pressure can increase corrosion.
Atmospheric O_2 leakage into plant system (e.g., piping, condenser, heat exchanger)	Increased oxygen increases corrosion.
Power plant material	(Should be selected to be resistant to the fluid at the site).
Stress levels in materials and especially cyclic stresses	High and/or repeated stress increases corrosion.
Crevices	Increases corrosion.
Presence of scale deposits	Can protect metal; also may create site for local corrosion.
Velocity of fluid	Increased velocity generally decreases corrosion.
Suspended solids content	Can abrade surface and increase corrosion.
Galvanic coupling of dissimilar metals	Increases corrosion.

complex processes that depend on the physical, chemical and metallurgical conditions at the solid-liquid interface. For this reason, the use of high alloy metals is necessary with corrosive geothermal fluids.

For stress corrosion cracking to occur, certain conditions must be present. The material must be in an electrolyte containing a certain amount of a cathodic depolarizer (oxygen, for example); the material must be under stress; and there must be enough contact time for an electromechanical action. Resulting crack propagation may be intergranular or transgranular, and may take minutes or years.

Sulfide cracking is a special case of stress corrosion cracking that can develop in geothermal injection facilities. This process is temperature and pH sensitive, and depends on the interaction between chloride and sulfide in solution. Because of the wide variation in chloride and sulfide concentrations in geothermal fluids, the sulfide cracking tendency of materials must be studied for each site.

Corrosion fatigue is related to stress corrosion cracking. This condition results from stress alteration (tension to compression) which reduces the service life of the material. Dissolved oxygen and the presence of H_2S in a salt solution lower the fatigue limits for some materials. Pumps are the primary target for corrosion fatigue in geothermal injection systems.

Erosion and cavitation in corrosive media are not completely understood. Erosion is created by abrupt momentum changes of the fluid or by impact of particulate matter in the fluid. Cavitation is associated with local hydrodynamic pressure reductions which cause bubble formation and collapse against a surface. Testing of full-scale equipment with the geothermal fluid in question is essential to determine if the equipment will resist erosion and cavitation.

Control of Corrosion--

In general, corrosion can be prevented or reduced in many ways, such as the following:

1) Changing the physical, chemical, or dynamic properties of the medium. Lowering the temperature usually causes a pronounced decrease in corrosion rate. Fluid flow generally increases corrosion, although there are exceptions; stainless steel, for example, has better corrosion resistance to a flowing medium than to a stagnant solution. Very high velocities should always be avoided, however,

because of erosion-corrosion effects. Removing oxygen by using an oxidizer is an old corrosion-control technique. In modern practice, oxygen removal can be accomplished by vacuum treatments, inert gas sparging, or addition of oxygen scavengers. Decreasing the corrosive concentration is also usually effective. Inhibitors may be used. They can be considered as retarding catalysts and can be classified according to mechanism of operation and composition: a) adsorption-type inhibitors (organic compounds which adsorb onto the metal surface); b) hydrogen-evolution poisons which retard the hydrogen evolution reaction; c) scavengers such as sodium sulfite and hydrazine which remove dissolved oxygen from aqueous solutions; d) oxidizers; and e) vapor-phase inhibitors.

2) Selection of proper material. Susceptibility to electrochemical attack and other types of corrosion must be evaluated. Use of alloys does not stop the corrosion process. When an alloy or other noble metal is used, some other less noble metal almost always is coupled to it and sacrificed to corrosion (cathodic protection). The use of stainless steel with chrome content higher than 10% is generally recommended. In any case, materials being considered should be tested with the geothermal fluid under the physical conditions anticipated during operation.

3) Protective coating. The protection any coating affords is directly proportional to its continuity. The most common coatings are cement, plastic, tar and epoxy, including Teflons. Controlled sodium silicate, calcium carbonate scale, and glassy phosphates have also been used.

An interesting case of natural corrosion protection exists at the Salton Sea geothermal field. Corrosion is generally not a problem above depths of 300 to 600 m (1,000 to 2,000 ft). Above 300 m (1,000 ft), silica scale apparently protects the casing from corrosion. In several downhole tests in production wells, only minimal corrosion was observed because of the development of a so-called "hard scale," a friable glassy (amorphous) material which formed as a thin film on the production lines. The "hard scale" was primarily a silica and iron oxide mixture with some sulfide.

4) Neutralizing pH of fluid.

5) Reducing the salt content of liquid waste may reduce corrosion in injection wells. Desalination has been studied at East Mesa Test Site, California. However, desalination to inject clean water is likely to be impractical in terms of cost and generation of solid waste or more concentrated brine. Additionally, altering the chemistry of the geothermal fluid prior to injection may create incompatibilities between the injected fluid, the formation and its fluid (Harding-Lawson, in press).

5.4.4 Hydrogen Sulfide

Significant amounts of dissolved H_2S are often present in geothermal steam condensate. The H_2S may lead to the creation of heavy metal sulfides, scale and to corrosion. H_2S can be removed by direct oxidation methods, including the following which are similar to those used to abate air pollution from cooling tower emissions:

- Direct injection of SO_2 in the waters to oxidize the H_2S to SO by the Claus reaction.
- Simultaneous injection of a catalyst such as sulfur dioxide or ferric ion, oxygen and air, or oxygen.
- Addition of a metal catalyst, such as iron, to the waters to promote direct oxidation by the oxygen dissolved in the circulating waters in the cooling towers.
- Addition of Cataban, a chelated iron compound, to catalyze the direct oxidation of H_2S.

Methods used for gas ejector emissions would not be as effective on condensate.

Oxidation in the cooling tower may result in the formation of insoluble metal sulfates (such as $CaSO_4$) and elemental sulfur, leading to pipe corrosion and plugging. Filtration or dispersion could be applied to remove the solids from the condensates prior to injection (Phillips, et al. 1976).

Eliminating silica deposits may prevent sulfide deposition by inhibiting nucleation and growth on substrates. Also, since sulfide solubility increases with decreasing pH, acidification may prevent sulfide deposition (Owen, 1977).

5.5 PHYSICAL PROBLEMS

Physical problems in a production-injection system involve potential land surface deformation and induced seismicity, hydrofracturing of confining formations and introduction of thermal stress. These problems and their solutions are discussed in this section.

5.5.1 Land Surface Deformation

Injection of spent geothermal fluid into the geothermal reservoir is generally recommended to minimize potential subsidence by maintaining the fluid balance in the reservoir. However, inhomogeneities in the subsurface materials will generally lead to localized areas of over-pressured and under-pressured rocks in the vicinity of the geothermal injection and producing wells, respectively. Lateral differences in hydrostatic pressure can lead to horizontal movements as well as the more obvious vertical ones. Changes in subsurface temperature associated with production and injection wells can cause additional movements in subsurface materials due to differential thermal expansion. However, these thermally induced movements will generally oppose the movements caused by fluid pressure changes (Harding-Lawson, in press).

Land Surface Monitoring and Modeling--

The first step in controlling land surface deformation is determining accurately the location, magnitude and direction of these movements. Monitoring these movements will allow them to be correlated with the rates and locations of geothermal production and injection, and the properties and inhomogeneities of the reservoir and overlying formations. If disruptive ground motion does occur, then these types of correlation, incorporated in analytic or mathematical models, will aid in determining the modifications of the production-injection scheme and possible prevention of further disruption.

Existing subsidence monitoring networks can be divided into three categories: 1) horizontal control networks, 2) vertical control networks, and 3) other measurement programs. For example, in Imperial Valley, California, networks of both regional and local extent have been established. The vertical network consists of first- and second-order level lines, allowing maximum vertical errors of 4.0 mm and 8.4 mm, respectively, per kilometer of distance surveyed. The regional horizontal network is capable of accuracies of 0.1 mm per kilometer, while the local networks are capable of accuracies of 2 mm per kilometer. In addition, developers of geothermal wells in the Imperial Valley are required by state and county ordinances to install several bench marks near each well and to periodically resurvey and tie them into the first- or second-order level lines, in order to detect local subsidence that may be related to geothermal production.

Tiltmeters and extensometers can aid in precisely defining the mechanism of the ground motion associated with geothermal subsidence. This data can be used to distinguish between subsidence due to geothermal fluid withdrawal and injection, and subsidence due to other mechanisms. Extensometers can be installed at various depths in wells where shallow ground water is being pumped close to geothermal developments; these can be used to monitor changes in water levels and compaction at different depths in boreholes located between the geothermal reservoir development and nearby farmlands. Data obtained can be used to differentiate between deep compaction caused by geothermal production and shallow compaction due to shallow ground water withdrawal.

Tiltmeters help determine whether the ground deforms as a stressed beam, develops vertical shear planes, or perhaps deforms with some combination of the two mechanisms.

Ground movements can also be estimated or predicted using computer models based on the theoretical relationships between the rate and duration of removal and injection and the hydrologic physical properties of the reservoir and overlying rocks. These calculations suffer both from inadequacies in the theory and from uncertainties in parameters (elastic constants, porosity, permeability, density, degree of homogeneity of the rock, and distribution of pre-existing in situ stresses). Nevertheless, the computer models are useful for calculating deformations over a wide range of possible parameters and source-sink locations. The more accurate the empirical measurements of these reservoir parameters, the greater the confidence in the estimated predictions. Ideally, an iterative combination of theoretical model studies with empirical data from a specific geothermal area will provide the best estimates of ground movement potential for a specific array of production and reinjection wells.

Additional information on the relationship between ground subsidence and the extraction of fluids for nongeothermal purposes is provided in papers by Poland (1973) and Poland and Davis (1969). Systems Control (1976) has published a comprehensive study of "The Analysis of Subsidence Associated with Geothermal Development". A report entitled "Geothermal Subsidence Research Program Plan" has been prepared for the U.S. Department of Energy as a means of providing a unified approach to guide future investigations of subsidence (Lawrence Berkeley Laboratory, 1977).

5.5.2 Induced Seismicity

Three relationships between seismic activity and geothermal occurrences have been noted: 1) geothermal anomalies are concentrated in seismically active regions of the world; 2) microearthquake activity has been correlated with geothermal anomalies; and 3) fluid withdrawal, with or without injection, may trigger local seismic activity.

Since most geothermal fields are in tectonically active regions, the possibility of triggering earthquakes by geothermal production and injection is of some concern. Existing injection well data have yielded clues to the ability of fluid injection to trigger earthquakes. Of the thousands of existing oil field and waste injection wells, only two instances of earthquakes triggered by fluid injection have been cited (Warner, 1977). One of these occurred at the Rocky Mountain Arsenal waste disposal well near Denver, Colorado, and another occurred at the Rangely Oil Field in northwestern Colorado (Raleigh, et al. 1976) where the largest event registered was a magnitude 6 earthquake. These earthquakes were believed to be caused by an increase in pore pressure that reduced the effective stress across fracture surfaces and resulted in shear failure. At the Rocky Mountain Arsenal chemical wastes were being injected under high pressure into deep wells in relatively dry formations. Seismic events up to magnitude 5 were recorded.

Because geothermal reservoirs are generally saturated, have high permeability and natural convective patterns, production and injection of fluids in these reservoirs are not analogous to the conditions at Rocky Mountain Arsenal and Rangely. The Geysers, California and Wairakei, New Zealand are both in areas of high natural seismicity. High microseismicity has been recorded since geothermal production and injection began at The Geysers. It is not known if this is higher than the natural microseismicity rate since there was no detailed pre-production microseismic monitoring. At Wairakei, no association between production/injection and increasing seismic activity has been noted. Injection into hot dry rock reservoirs might have a greater potential for generating earthquakes (Ridley and Taylor, 1976). Since the formation is not initially saturated, the introduction of fluid will significantly lower the effective stress in the rocks, thereby lowering the force necessary to cause displacement in fractures.

Control of Induced Seismicity--

The possibility of triggering earthquakes can be minimized by not exceeding the original pore pressure of the fluids. Reservoir pressure reduction resulting from production of geothermal fluid will generally be transmitted through the reservoir to injection well locations. Pressure increases due to injection will be greatest close to the injection well, but these increases will be exceeded by the reservoir pressure reductions within a moderate distance. This can be a very delicate situation but, generally, injection-induced seismicity may be a problem only if a fault is located within a higher pressure area close to an injection well.

Avoiding changes in pore pressure in overlying fresh water aquifers is another reason to isolate the injection well from those aquifers. The injection well or any abandoned well near an injection well may provide a pathway for upward migration of liquid wastes into overlying aquifers (see Section 3.2.2, Potential Pollutant Mechanisms and Pathways). Entry of liquid could increase pore pressure, thereby increasing seismicity.

Withdrawal of geothermal fluids may alter deep ground water flow patterns, and perhaps even affect flow rates in overlying aquifers. The effect of these alterations on the tectonic stress regime is unknown. Several years of continuous monitoring will be required to understand the effects of fluid withdrawal and injection.

Measures to mitigate induced seismicity would involve careful regulation of fluid production and injection rates. Although this mechanism is generally understood, its application, which would include computer analyses of reservoir properties, existing and induced stress fields, and ground water flow pattern, remains speculative.

Two criteria can be considered useful in differentiating induced earthquakes from naturally occurring ones: changes in the frequency-magnitude (recurrence) statistic in the area of the geothermal field; and changes in depth and location of events from those occurring prior to production activity (Phelps and Anspaugh, 1976). In order to apply these criteria, studies are normally made both prior to development and during utilization of a geothermal resource to:

1) determine the "baseline" level of naturally occurring earthquakes, including location and depth; and

2) monitor the actual magnitude and distribution of earthquakes during utilization of the reservoir.

5.5.3 Hydrofracturing of Confining Formations

Hydraulic fracturing (hydrofracturing) is a technique used in nongeothermal injection to increase formation injectivity. It is done by injecting fluid at pressures higher than the fracture pressure of the system, thereby causing the reservoir rock to fracture (Sun, 1973; Warner and Lehr, 1977).

In geothermal injection, hydrofracturing should be avoided unless the fracture strength of the confining formations or caprock is significantly greater than that of the reservoir rock. Induced fracturing of the caprock or confining formations may disrupt the natural hydrologic regime. This could be detrimental to reservoir productivity by releasing reservoir pressure. Additionally, geothermal fluid escaping through the induced fractures could degrade water in overlying aquifers.

In reservoirs where the rock strength cannot be measured, the original hydrostatic pressure of the reservoir must be determined. The injection pressure should be carefully monitored to avoid exceeding the original reservoir pressure. Where the fracture pressure of the rock is known, it must not be exceeded during injection.

5.5.4 Thermal Stress

In the special case of injection of cold water into a hot dry rock formation for heat recovery, the resulting temperature gradient in the rock needs to be considered. The differential thermal stress fields created by the cold water may result in more extensive fracturing than that desired for heat recovery. Research is being done on this problem by the Futures Group (1975).

5.6 INJECTION SYSTEM DESIGN

Reservoir engineering calculations and reservoir modeling are integral preliminary phases of designing the physical injection system. These preliminary studies will provide information on the optimum production and injection zones and rates. This will thereby influence decisions on optimum locations, depths and capacities of wells and whether intervals are perforated or open. Some example results of these types of calculations are included in Section 2.4

After the reservoir engineering and modeling phase, four aspects remain in the physical design of a geothermal injection system: type of pretreatment, fluid delivery system, well design and monitoring of operation. These aspects are discussed below.

5.6.1 Pretreatment

The type of pretreatment depends on the downhole behavior of the liquid waste. Most geothermal fluid will require some removal of dissolved and suspended solids prior to injection. Settling ponds, tanks or filtration can be used to remove solids. The liquid waste may be chemically treated to reduce corrosivity and scaling. At the expense of heat loss, fluid from liquid-dominated reservoirs may be treated prior to entering the energy conversion system. This would reduce chemical problems throughout the system.

Various preinjection treatment methods for all types of wastewater are described in detail by Warner (1977). Those methods applicable to scaling control in geothermal wells are summarized in Table 5.2.

5.6.2 Delivery Systems

Although gravity is normally a sufficient force for geothermal waste injection, it may be necessary in some instances to pump the waste down the hole. Often, for example, plugging of the formation will occur after injection has begun. To maintain an adequate injection rate, the pressure must be increased by pumping.

The type and size of pump may best be selected after the well is installed and pumping tests are made to determine the wellhead pressures needed for injection. Pump selection is made on the basis of wellhead pressure, volumes to be injected, and injection rate variability. Corrosion resistance is also a major consideration in pump selection and design.

Centrifugal pumps are the most common type used for injection. For low-pressure injection (less than 350 kPa [50 psi]), single-stage centrifugal pumps are adequate. Higher wellhead pressures will require multiplex piston-type or multi-stage centrifugal pumps (Warner, 1977).

5.6.3 Well Design

Injection well design is one of the most critical aspects of injection well technology. For adequate pollution protection rigorous safety specifications must be designated and enforced. This includes specification of tubing placement within the casing, monitoring fluid pressures, complete grouting and welding, placement of packers, and selection of corrosion-resistant casing and tubing.

Recommendations have been made for injection well completion design for hazardous waste disposal (Reeder, et al. 1977). Following these recommendations for geothermal injection well design and construction will ensure maximum protection of usable subsurface waters and economic minerals. Fig. 5.5 is a detailed diagram of the well completion recommended for maximum protection during injection of hazardous waste. The first casing string (largest diameter) extends at least 15 m (50 ft) below the lowest fresh water zone penetrated by the well, and is grouted from the bottom to the surface. This and subsequent

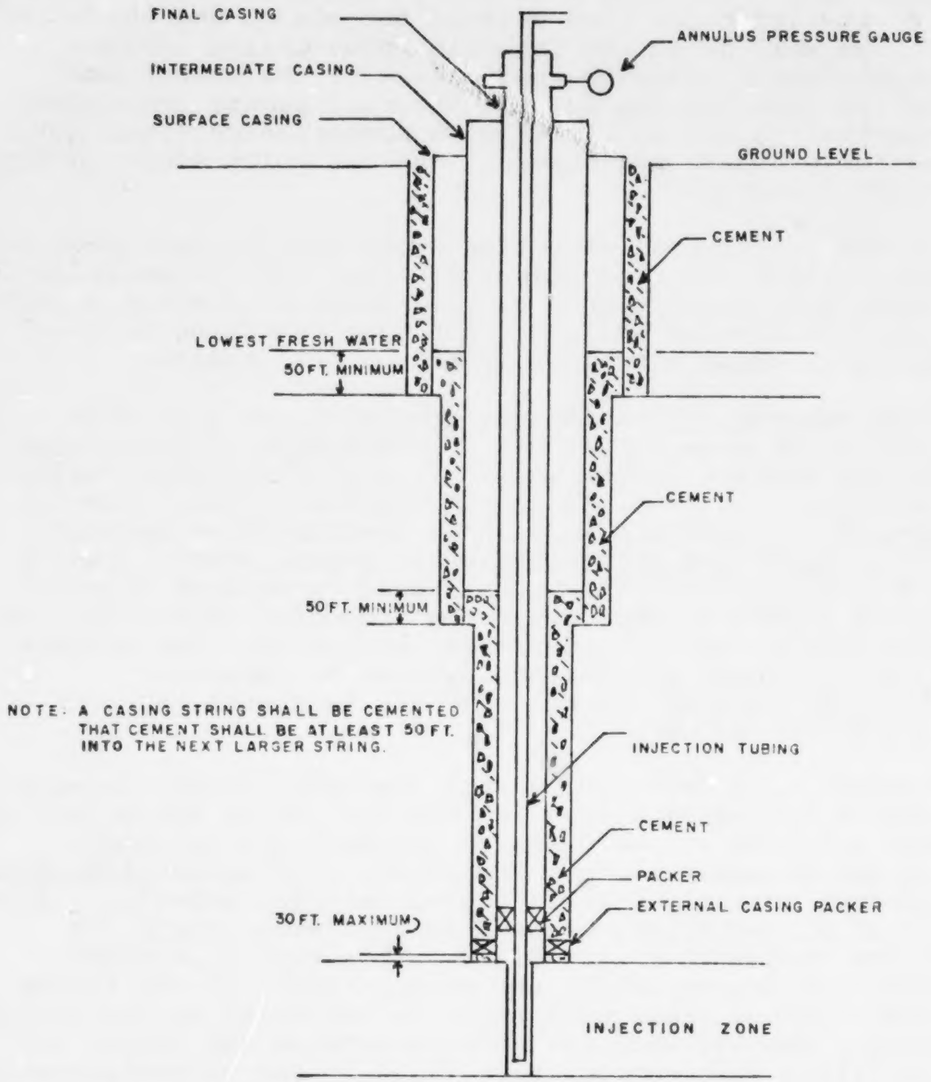
FINAL CASING
INTERMEDIATE CASING
SURFACE CASING
ANNULUS PRESSURE GAUGE
GROUND LEVEL
CEMENT
LOWEST FRESH WATER
50 FT. MINIMUM
CEMENT
50 FT. MINIMUM
NOTE: A CASING STRING SHALL BE CEMENTED THAT CEMENT SHALL BE AT LEAST 50 FT. INTO THE NEXT LARGER STRING.
INJECTION TUBING
CEMENT
PACKER
EXTERNAL CASING PACKER
30 FT. MAXIMUM
INJECTION ZONE

Figure 5.5 Well completion for maximum protection during hazardous waste injection. (Reeder, et al. 1977)

smaller diameter strings have 15 m (50 ft) of cemented annulus overlap with each other. All the casing is mechanically centered for a consistent grout seal thickness. Packers are installed at the top of the injection zone between the casing and the borehole wall, as well as in the injection tube-casing annulus. The external packer helps prevent attack of the cement and casing by the injected fluid. The interior packer seals the annulus so that it can be filled with noncorrosive fluid and monitored for pressure and chemical changes which might indicate leaks in the system.

Normally, geothermal injection wells are designed much like production wells. The production-injection zone in an injection well is sometimes cased with a slotted liner to prevent sloughing, whereas production wells may not require casing in that zone. Fig. 5.6 shows a typical injection well design.

If the reservoir rock is very competent, an open hole completion can be used. This has the advantage of maximizing the receiving surface in the well. It also eliminates casing and screen corrosion problems in the injection zone. Careful completion of an injection well above the injection zone is critical in preventing contamination of ground water. Casing must be selected for corrosion resistance as well as internal and external pressure. Welds must be inspected carefully. The casing may require coating to prevent corrosion. The annulus between the well bore and the casing must be cemented completely. No pockets in the grout are tolerated, as they provide pollutant pathways.

To protect the well casing from corrosive fluid, injection tubing should be placed within the casing. Grade and weight of tubing are selected on the basis of internal and external pressures and on axial loads. The tubing size selected depends on the planned injection rate. Tubing material selection, like selection of all materials exposed to geothermal fluid, is based on the chemistry of the fluid. This tubing provides extra pollution protection in two ways. First, if the tubing fails, the injected fluid will still be contained by the casing and packers. Second, when the annulus between the tubing and casing is filled with noncorrosive fluid it can be continuously monitored for pressure changes which may indicate a leak in the system. Unlike casing, this tubing can be replaced if it fails. Packers should be installed in the annular space between the tubing and casing to seal off sections. This sealing isolates the injection zone and prevents circulation of the injected fluid inside the casing. Since geothermal injection wells will be constructed under current regulations they should have all the features of this recommended design and construction.

Fig. 5.6 shows three types of open-hole completions that have been used in hazardous waste disposal wells. The one on the right has all the features of the recommended design. Although each of the remaining completions provide more protection than injection through a simple cased hole, they do not provide as much protection as the recommended completion. The one on the left does not isolate the fluid filling the annulus between the injection tubing and the casing. In this situation the injected fluid can flow into the annulus thereby causing casing corrosion. The absence of a packer to contain the annular fluid under a constant pressure also prevents detection of leaks through the tubing. The center diagram illustrates similar deficiencies although pumping water through the annulus lessens the possibility of corrosion from injected fluid flowing into the annulus. Additional drawbacks of this design are: 1) the amount of acceptable quality water that is required to place in the well; and 2) the reduction in the amount of waste fluid the formation can accept due to the emplacement of the additional water injected through the annulus.

5.6.4 Monitoring Injection Well Operation

The flow rate, injection wellhead pressure and annulus fluid pressure must be monitored continuously to provide the necessary data for reservoir management, well maintenance and pollution control. Chemistry of the injected fluid and annulus fluid should also be monitored regularly.

Annulus fluid pressures and chemistry are monitored to detect leakage in the system. Depending on the composition of the fluid, adequate chemical monitoring may be accomplished by placing conductivity probes in the annulus, or by analyzing return flow for contamination in continuous cycling annulus fluid.

Corrosion rate can be determined by placing sample strips of the tubing and casing material in the well, and checking them periodically for weight loss.

Where injecting chemically active fluid, it is important that the well be shut down periodically for inspection and testing. Inspection methods for casing, tubing, cement and well bore include: (1) pulling the tubing and inspecting it visually or instrumentally; (2) electromagnetic caliper or televiewer logging of tubing or casing in the hole; (3) pressure testing of casing; (4) bond logging of casing cement; and (5) inspection of casing cement or well bore with injectivity or temperature profiles (Warner, 1975). Downhole geophysical methods are described in detail by Harding-Lawson (in press).

DESIGN:	Fluid Filled Annulus, Pressure Monitor, No Packer in Annulus, Tubing Hanging Free	Water Injected into Annulus, Pressure Monitor	Fluid Filled Annulus with Pressure Monitor and Packer
LEAK DETECTION CAPABILITY:	Minimal	Minimal	Positive
CASING PROTECTION:	Limited	Limited	Excellent

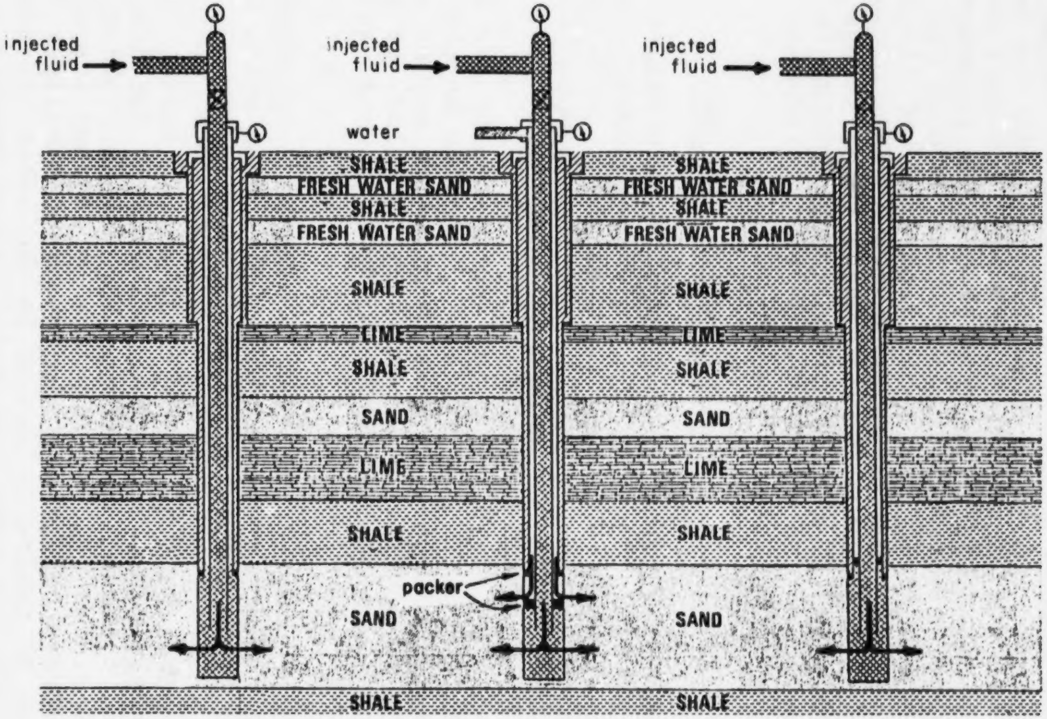
injected fluid
injected fluid
injected fluid
water
SHALE
FRESH WATER SAND
SHALE
FRESH WATER SAND
SHALE
LIME
SHALE
SAND
LIME
SHALE
packer
SAND
SHALE

Figure 5.6 Comparison of three types of completions used in hazardous waste injection wells. (modified from Reeder, et al. 1977)

5.6.5 Cost Analysis

The cost of a geothermal injection system varies as widely as the size, type, and chemistry of geothermal reservoirs. The following is a list of variable factors which control the cost of a system:

Installation costs:

- Well drilling - depends on the number and depth of wells, and the type of material penetrated. Fig. 5.7 gives estimated average drilling costs.
- Well completion - depends on the number, depth, material penetrated, and on the fluid chemistry. Highly corrosive fluids may require expensive resistant materials for grouting, tubing, casing and other well components.
- Wellhead apparatus - higher injection pressures will generally necessitate more expensive injection pumps.
- Treatment facilities - the chemistry and volume of the fluids are determining factors in selecting types and size of preinjection treatment facilities.
- Surface conveyances - production and injection, well spacing (which, in turn, depends on the reservoir dynamics), length of surface conveyance from production to injection wells. The size of the conveyances depends on the volume of fluids injected. The type, and therefore the cost, of the material used for the conveyances is dependent upon the chemistry of the water.

A literature survey revealed examples of actual capital costs for some geothermal well systems. These data are presented in Table 5.5 showing, where possible, the breakdown according to size and depth of the well and costs of construction, pumps and pipeline. Table 5.6 presents the capital costs for injection systems for four well capacities.

As in any economic analysis, the location and time of the development must be considered. Prices vary from one geographic area to another and, in general, construction costs increase with distance from a major city where supplies and equipment can be obtained and manufactured. Engineering News-Record periodically publishes construction cost indexes which enable cost adjustments based on geographic area (Engineering News-Record, 1978).

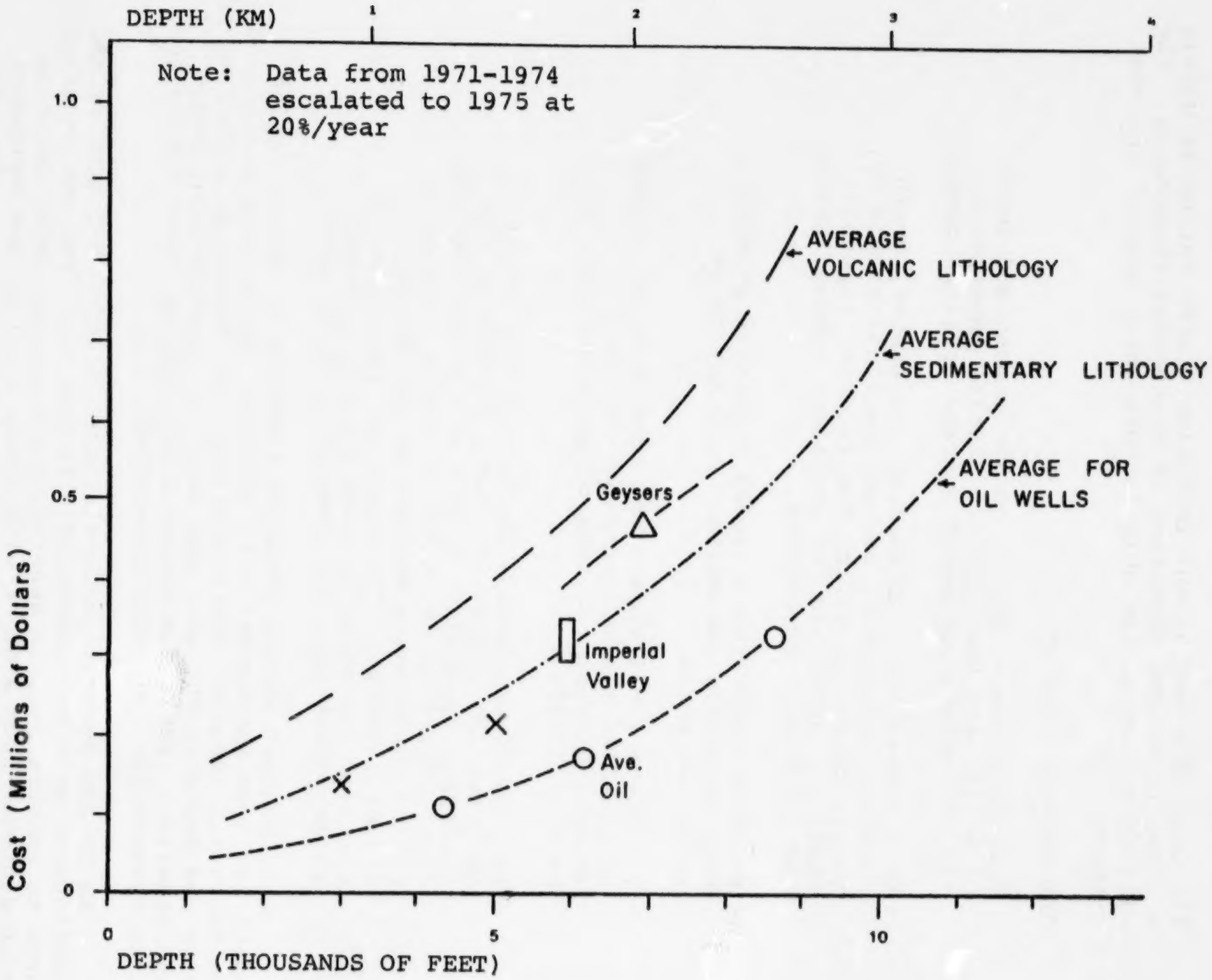

Figure 5.7 Typical well drilling costs. (Meidav and Sanyal, 1976)

TABLE 5.5 CAPITAL COST OF INJECTION WELLS, DATA FROM THE LITERATURE (Sung, et al. 1977)

Reference	Pearson	Pearson	TRW	Glass	Sung, et al.
Date Published	Oct. 76	Oct. 76	Dec. 74	May 77	1977
Type Well	Injection	Injection	Steam Production	Steam Production	Injection
Location	East Mesa, Ca.			The Geysers, Ca.	AVERAGE
Diameter (in.)			9-5/8		
Total Vertical Depth (ft.)			7,000	7,000 to 8,000	
Straight (S) or Directional (D)	S	D (48°)	D (30°)		
Construction Cost	$403,077	$535,448			
- Drilling Contractor Cost			$169,000	$658,000	$170,000
- Mud Expense			20,000	30,000	20,000
- Casing & Tubing			10,000	124,500	70,000
- Cementing			25,000	50,000	40,000
- Logging			23,000	33,000	20,000
- Perforation			40,000		50,000
- Wellhead Equipment				20,000	40,000
- Engineering Supervision				28,000[a]	10,000
- Control Sys.	22,831				30,000
Injection Pump	54,200				50,000
Injection Pipeline	224,000				0[c]
Total Capital Cost				$1,003,500[b]	500,000[d]

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[a] Includes overhead

[b] Includes miscellaneous costs amounting to $60,000

[c] No pipeline is required if directional drilling is used. This component will cost several hundred thousand dollars if required

[d] The total capital cost may vary from approximately $300,000 to $1 million. $500,000 is considered to be a reasonable average based on costs of a number of existing geothermal and industrial waste disposal wells.

TABLE 5.6 CAPITAL COSTS FOR INJECTION SYSTEMS FOR FOUR WELL CAPACITIES (Hartley, 1978)

Flow	Well Capacity: 200 lpm/well			Well Capacity: 1000 lpm/well			Well Capacity: 4000 lpm/well			Well Capacity: 8000 lpm/well		
	Wells Required	Initial Capital Cost	Annualized Cost Per Unit of Flow[b]	Wells Required	Initial Capital Cost	Annualized Cost Per Unit of Flow[b]	Wells Required	Initial Capital Cost	Annualized Cost Per Unit of Flow[b]	Wells Required	Initial Capital Cost	Annualized Cost Per Unit of Flow[b]
(liters/ minute)		($10^6)	($/1000ℓ)	($/1000ℓ)	($10^6)	($/1000ℓ)		($10^6)	($/1000ℓ)		($10^6)	($/1000ℓ)
10	1	0.5	10.60									
100		0.5	1.06	1	0.5	1.06						
500	2	1.0	0.42	1	0.5	0.212						
1000	5	2.5	0.53	1	0.5	0.106	1	0.5	0.106			
4000	20	10.	0.53	4	2.0	0.106	1	0.5	0.0264	1	0.5	0.0264
5000	25[a]	12/5	0.53	5	2.5	0.106	2	1.0	0.0422	1	0.5	0.0211
10,000				10	5.0	0.106	3	1.5	0.0316	2	1.0	0.0211
15,000				15	7.5	0.106	4	2.0	0.0281	2	1.0	0.0141
30,000				30[a]	15.	0.106	8	4.0	0.0281	4	2.0	0.0141
50,000							13	6.5	0.0274	7	3.5	0.0148
100,000							25[a]	12.5	0.0264	13	6.5	0.0137
350,000										44	22.	0.0133

[a] Arbitrary limit

[b] Total cost is annualized based on C = P(CRF), where P - total cost and CRF is capital recovery factor at 8% interest and 30-year period. The demand factor for the well is assumed to be 80%.

Operation and Maintenance Costs:

- Injection pumping - depends on the volumes and the injection pressure.

- Pretreatment - depends on the chemistry of the geothermal fluid.

- Surface conveyance - depends on the size and configuration of the system, the volumes transported, and whether pumping is required.

- Removal of scale from injection system components - depends on the chemistry and volumes of the fluid and the types of scale control methods employed in the system.

- Replacement of components - depends upon the corrosivity of the fluids and the resistance of the component material to chemical attack.

- Monitoring costs - the extent of monitoring systems will depend on regulatory specifications, the size, depth and dynamics of the reservoir and the desired degree of aquifer protection.

5.7 CASE HISTORIES

5.7.1 Wairakei, New Zealand

The water-dominated field at Wairakei has been in production since 1951. Injection has not been practiced here and up to 4.5 m (14.8 ft) of ground subsidence occurred between 1964 and 1974 (Stilwell, et al. 1976). This subsidence correlates with the decrease in aquifer pressure and the total mass output of the field (Hatton, 1970).

Injection might help control subsidence, but for fear of contributing to the declining temperature of the reservoir (from 250°C [482°F] in 1951 to 238°C [460°F] in 1970) injection is not presently done regularly. The high silica content of the water might create scaling and plugging in injection wells (Rothbaum and Anderton, 1976).

5.7.2 Otake, Japan

The Otake geothermal field produces wet steam (80% liquid) from a 300 m (1,000 ft) thick, highly permeable, fractured tuff breccia. The reservoir rock is overlain and underlain by relatively impermeable volcanics (Yamasaki, et al. 1970).

The 10 MW power plant at Otake is solely for experimentation. Four wells provide 109,000 kg/hour (240,000 lb/hr) of steam to the turbine, with more than 400,000 kg/hr (880,000 lb/hr) of hot water separated prior to power generation. All the geothermal water is injected into three wells completed in the production zone (Kubota and Aosaki, 1976).

Injection testing began at Otake in 1968 and tests were conducted from 1968 to 1971 using two converted production wells. Drilling of the three injection wells now in use began in 1972. Wells were drilled between 150 and 500 m (500 and 1,640 ft) from the nearest production well to enable determination of minimum spacing between future production and injection wells. Waste fluid is injected below the producing level to prevent thermal degradation of the reservoir or chemical degradation of overlying aquifers.

Injection wells at Otake are cased essentially the same as production wells, with casing to the bottom of the caprock and cementing of the entire annular space. No injection tubing is used. The wellhead valve is equipped with a return pipe for shutoff if a blowout occurs. A flow meter on the wellhead measures both velocity and volume.

Injection capacities of the three wells have dropped significantly. The capacity of one well, for example, decreased from 310,000 kg/hr to 120,000 kg/hr (680,000 to 260,000 lb/hr) during the first three years of operation. The ground water level rose 30 m (100 ft) and 25 mm (1 in) of silica scale had accumulated on the well wall at the wellhead. However, chemical monitoring of surface waters indicates that the injected water is not leaking to the surface (Kubota and Aosaki, 1976).

Prior to injection, production was declining by about 6% per year. (In four years the power output went from 11 MW to 8.7 MW.) After injection began, the power station output rose to 10 MW without additional production wells.

Injection has apparently caused no temperature drop in the reservoir or surrounding formation. The enthalpy of the produced fluid has remained essentially constant.

Seismicity has been monitored at four stations near the wells since injection began. No anomalous earthquakes have been recorded (Kubota and Aosaki, 1976).

5.7.3 Cerro Prieto, Mexico

Liquid waste is currently stored in an evaporation and sedimentation pond on clayey saline soils showing thermal manifestations. Although no adverse effects have been associated with this storage pond final disposal of the waste fluid will be by surface discharge or injection. Two waste canal discharge schemes have been proposed: one to the Sea of Cortez and one to the Laguna Salada. The 75 MW Cerro Prieto geothermal plant produces wastewater with high concentrations of SiO_2, NaCl, KCl, and other salts. Injecting into a known highly permeable area west of the fields might be feasible for waste control, as well as reservoir recharge (Mercado, 1976).

5.7.4 Valles Caldera, New Mexico

During 1973 and 1974, injection tests were made in two wells in the Valles Caldera liquid-dominated reservoir. Water from a separator flowed into holding ponds and was then injected. A total of about 380,000 cu m (100 million gallons) was injected during that time without impaired injectivity (Chasteen, 1976).

5.7.5 The Geysers, California

Injection at The Geysers geothermal area began in 1969, nine years after production began. By 1975, over 15 million cu m (about 4 billion gal) had been injected. In 1967, the total injection rate was about 0.21 cu m/sec (55 gpm) into six wells. About 100 production wells have been drilled into the metamorphosed highly fractured shale and sandstone reservoir. Wells are about 1,000 m (3,300 ft) deep on the average, with some deep wells up to about 3,000 m (10,000 ft) (Chasteen, 1976).

The original injection wells were unsuccessful production wells, into which slotted liners were placed to keep the holes open for injection. The lower zone in the first injection well became plugged, forcing the waste into a higher horizon and ultimately cooling a nearby production well. Injection wells are now drilled deeper than producing wells and as far as possible from producing regions.

Preinjection settling basins allow solids to precipitate, thereby helping to prevent contamination and plugging of the injection wells. Oxidation and corrosion are controlled by deaerating the injection system. No pumping is required for injection at The Geysers.

Elemental sulfur in the injected water clogs the formation around the wells, thereby decreasing injection rates. By shutting the well off and allowing it to reach the 250°C (482°F) reservoir temperature, the sulfur melts (at 114°C [237°F]). It can then be flushed away from the hole by resuming injection.

Subsidence and microseismicity are being monitored at The Geysers by the U.S. Geological Survey. The area exhibits considerable microseismic activity. However, no subsidence or anomalous microseismic activity has been observed which can be correlated to geothermal development.

5.7.6 Larderello, Italy

Some injection tests have been done in and around the producing regions of this dry steam field, although the condensate is not currently disposed of by injection.

In 1973 in the Viterbo region, fluid from one well was injected into another, 4 km (2.5 mi) away. The 62°C (144°F) fluid was injected under gravity for nine days at rates ranging from 0.0035 to 0.0355 cu m/sec (55 to 567 gpm) (Calamai, et al. 1973). A seismic control program involving five microseismic stations was operated for 40 days before, during and after the injection test. No microshocks resulted from the injection test (Cameli and Carabelli, 1976).

5.7.7 Ahuachapan, El Salvador

The Ahuachapan field produces high temperature, high salinity wet steam from a fractured, high permeability reservoir 500 to 1200 m (1,600 to 3,900 ft) below the surface. Temperatures of the reservoir exceed 200°C (392°F) and have 8000 ppm total dissolved salts and 650 ppm SiO_2. Silica scaling is a serious problem, and has rendered surface disposal uneconomical due to clogging of pipes and ditches.

Injection experiments were done between 1970 and 1975. The first injection well was drilled outside the reservoir to avoid cooling the geothermal fluid, but permeabilities were too low for effective injection. This forced a major revision in test plans.

Several factors led to the decision to test injection directly into the reservoir. Based on heat exchange studies, it was determined that cooling of the reservoir by injected water would be within acceptable limits (Bodvarsson, 1972). Because of the high permeability of the reservoir, injection into it would not require as much energy as the initial test into low permeability material. Recycling the residual heat of the wastewater might prolong the productive life of the reservoir.

A well was drilled in the production area for the injection experiments, with the intent of converting it to a producer. It was completed with a retractable liner which was extended from the production casing to the bottom of the hole at 952 m (3,123 ft) below the surface. This was done to inject into permeable horizons below the production zone.

Study of the chemical equilibrium at Ahuachapan indicated that silica deposition could be avoided by separating the steam from the water and maintaining the wastewater at a temperature above 150°C (302°F). Also, the temperature of the injected fluid should not differ from that of the reservoir rock by more than 50°C (122°F). By maintaining separator and wastewater temperature between 152°C and 153°C (306°F and 307°F), no scaling or mineral deposition occurred during the 244 days of injection experiments.

Temperature, pressure and chemical changes were monitored in surface springs and production wells during the injection tests. No changes were noted. Tritium tracers injected into the injection zone showed up in small concentrations in production wells within 500 m (1,600 ft) of the injection well. However, none of the tracer has appeared in surface water or fresh water aquifers in the area.

Following the injection tests, the well was put into production. Original production temperatures were reached in about the same length of time that injection was performed (Einarsson, et al. 1976).

5.7.8 Imperial Valley Fields, U.S.A.

The Imperial Valley is a large geothermal region in the southwestern U.S. Reservoirs in this region are in sedimentary rock; some have intergranular permeability and some have fracture permeability. The fields are generally liquid-dominated and though the temperatures are high, severe corrosion and scaling problems have inhibited development of the resource. Several test facilities are being designed and operated in the Imperial Valley. The following fields are among those which are being used for injection testing.

East Mesa--

The East Mesa geothermal field is a liquid-dominated reservoir in fractured sandstone. High-temperature gradients, relatively low salinity fluids (less than 30,000 ppm) and a thick production zone make East Mesa an attractive area for development. The Bureau of Reclamation has established East Mesa as a national facility for testing materials and equipment in a geothermal environment.

In 1975, testing began on experimental injection well Mesa 5-1. Geothermal brine from a holding pond was injected at rates between 0.003 and 0.015 cu m/sec (55 and 235 gpm) (Mathias, 1976). Intermittent booster pumping was done as the injection rate decreased with total injection volumes. High corrosion of the instrument used for downhole pressure monitoring was probably caused by high dissolved oxygen content.

Mixing of fluids from two wells caused great amounts of calcium carbonate to precipitate in the injection pipeline system. The precipitate was washed out with water but it has demonstrated the problem of mixing waters for injection (U.S. Dept. of the Interior, 1977).

Niland--

Union Oil Company tested injection in this liquid-dominated reservoir in 1964 and 1965. After overcoming the 1.4 MPa (200 psig) wellhead pressure, the testers found that the relatively heavy, cold injected fluid effectively created a vacuum on the injection system. This resulted in an injection rate of about 0.04 cu m/sec (600 gpm), and a total of 480,000 cu m (126,000,000 gal) of fluid was injected. Injectivity loss or reservoir response due to the injection test was not observed (Chasteen, 1976).

Heber, California--

The liquid-dominated Heber field is the site of an experimental geothermal facility. Plans for the Heber geothermal demonstration plant involve installing 50 to 60 production wells and 20 to 30 injection wells to serve a 200 MW plant. Nearly all the produced geothermal fluid will be injected, with injection wells located on the perimeter of the reservoir, about 3.2 km (2 mi) from the production area. Wells in the field produce between 2.2 x 10^5 and 3.0 x 10^5 kg/hr (4.8 and 6.6 x 10^5 lb/hr) and each injection well is expected to dispose of about twice the volume that each production well produces. Scaling is not expected to be a problem with this saline geothermal fluid.

5.8 RESEARCH NEEDS

The area of liquid waste injection technology poses complex problems. The most important of these are outlined below.

5.8.1 Chemical Aspects

1) Well scaling and formation plugging mechanisms need to be better understood in order to control these processes and to determine the longevity of injection wells. Chemical aspects of scaling and plugging that require further research include:

    a) silication chemistry;

    b) chemical inhibitors;

    c) effects of process variables;

    d) effects of mixing fluids from different wells; and

e) injection/receiving fluid and injection fluid/receiving formation interactions.

2) Corrosion mechanisms and prevention measures deserve attention. The following need study:

   a) removal and disposal of corrosive components of geothermal fluids; and

   b) site-specific studies of corrosion-resistant materials.

5.8.2 Equipment Development Needs

Specialized equipment is essential for a better understanding of the subsurface injection horizons and for system maintenance. Some candidates for research and development include:

1) well logging tools and interpretation techniques for use in high-temperature environments and nonsedimentary lithologies;

2) instruments such as permeability indicators and electrochemical monitoring tools; and

3) injection emergency backup systems.

5.8.3 Reservoir Engineering

The following aspects of geothermal reservoir engineering need further study before geothermal reservoirs can be properly managed. These include:

1) the understanding of pore geometry; particularly the hydraulics of fracture permeability,

2) thermal stress in production zones,

3) advanced methods and interpretation for injection tests, and

4) computer modeling of reservoir response with special attention to:

   - pore geometry,

   - temperature gradients--vertical and horizontal, both natural and imposed,

- existing hydraulic gradients and flow dynamics including fluid density, pressure and TDS concentration
- changes in fluid dynamics imposed by production and injection wells, and
- decrease in injectivity due to plugging.

5.8.4 Physical Problems

Physical problems in injection procedures which need further research are:

1) earthquake stimulation--the potential for induced seismicity,

2) hydrofracturing--to increase injectivity while preventing damage to reservoir caprock, and

3) the effect of reservoir pressure changes on surface buckling.

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APPENDIX A

EPA POSITION ON SUBSURFACE EMPLACEMENT OF FLUIDS

(from Federal Register, April 9, 1974, p. 12922-12923)

INTRODUCTORY COMMENTS

The Environmental Protection Agency, in concert with the objectives of the Federal Water Pollution Control Act, as amended (33 U.S.C. 1251 et seq.; 86 Stat. 816 et seq.; Pub. L. 92-500) " . . . to restore and maintain the chemical, physical, and biological integrity of the Nation's water" has established an EPA policy on Subsurface Emplacement of Fluids by Well Injection" which was issued internally as Administrator's Decision Statement No. 5. The purpose of the policy is to establish the Agency's concern with this technique for use in fluid storage and disposal and its position of considering such fluid emplacement only where it is demonstrated to be the most environmentally acceptable available method of handling fluid storage or disposal. Publication of the Policy as information establishes the Agency's position and provides guidance to other Federal Agencies, the States, and other interested parties.

Accompanying the policy statement are "Recommended Data Requirements for Environmental Evaluation of Subsurface Emplacement of Fluids by Well injection well system; and to insure ments is to provide guidance for potential injectors and regulatory agencies concerning the kinds of information required to evaluate the prospective injections well system; and to insure protection of the environment. The Recommended Data Requirements require sufficient information to evaluate complex injection operations for hazardous materials, but may be modified in scope by a regulatory agency for other types of injection operations.

The EPA recognizes that for certain industries and in certain locations the disposal of wastes and the storage of fluids in the subsurface by use of well injection may be the most environmentally acceptable practice available. However, adherence to the policy requires the potential injector to clearly demonstrate acceptability by the provision of technical analyses and data justifying the proposal. Such demonstration requires conventional engineering and other analyses which indicate beyond a reasonable doubt the efficacy of the proposed injection well operation.

Several issues within the policy should be highlighted and explained to avoid confusion. One of the goals of the policy is to protect the integrity of the subsurface environment. In the context of the policy statement, integrity means the prevention of unplanned fracturing or other physical impairment of the geologic formations and the avoidance of undesirable changes in aquifers, mineral deposits or other resources. It is recognized that fluid emplacement by well injection may cause some change in the environment and, to some extent, may preempt other uses.

Emplacement is intended to include both disposal and storage. The difference between the two terms is that storage implies the existence of a plan for recovery of the material within a reasonable time whereas disposal implies that no recovery of the material is planned at a given site. Either operation would require essentially the same type of information prior to injection. However, the attitude of the appropriate regulatory agency toward evaluation of the proposals would be different for each type operation. The EPA policy recognizes the need for injection wells in certain oil and mineral extraction and fluid storage operations but requires sufficient environmental safeguards to protect other uses of the subsurface, both during the actual injection operation and after the injection has ceased.

The policy considers waste disposal by well injection to be a temporary means of disposal in the sense that it is approved only for the life of an issued permit. Should more environmentally acceptable disposal technology become available, a change to such technology would be required. The term "temporary" is not intended to imply subsequent recovery of injected waste for processing by another technology.

Paragraph 5 of the policy and program guidance provides that EPA will apply the policy to the extent of its authorities in conducting all EPA program activities. The applicability of the policy to participation by the several States in the NPDES permit program under section 402 of the Federal Water Pollution Control Act as amended has been established previously by § 124.80(d) of Part 124 entitled "State Program Elements Necessary for Participation in the National Pollutant Discharge Elimination System," 37 FR 28390 (December 22, 1972). These guidelines provide that each EPA Regional Administrator must distribute the policy to the Director of a State water discharge permit issuing agency, and must utilize the policy in his own review of any permits for disposal of pollutants into wells that are proposed to be issued by States participating in the NPDES.

Dated: April 2, 1974.

JOHN QUARLES,
Acting Administrator.

ADMINISTRATOR'S DECISION STATEMENT NO. 5 EPA POLICY ON SUBSURFACE EMPLACEMENT OF FLUIDS BY WELL INJECTION

This ADS records the EPA's position on injection wells and subsurface emplacement of fluids by well injection, and supersedes the Federal Water Quality Administration's order COM 5040.10 of October 15, 1970.

Goals. The EPA Policy on Subsurface Emplacement of Fluids by Well Injection is designed to:

(1) Protect the subsurface from pollution or other environmental hazards attributable to improper injection or ill-sited injection wells.

(2) Ensure that engineering and geological safeguards adequate to protect the integrity of the subsurface environment are adhered to in the preliminary investigation, design, construction, operation, monitoring and abandonment phases of injection well projects.

(3) Encourage development of alternative means of disposal which afford greater environmental protection.

Principal findings and policy rationale. The available evidence concerning injection wells and subsurface emplacement of fluids indicates that:

(1) The emplacement of fluids by subsurface injection often is considered by government and private agencies as an attractive mechanism for final disposal or storage owing to: (a) the diminishing capabilities of surface waters to receive effluents without violation of quality standards, and (b) the apparent lower costs of this method of disposal or storage over conventional and advanced waste management techniques. Subsurface storage capacity is a natural resource of considerable value and like any other natural resource its use must be conserved for maximal benefits to all people.

(2) Improper injection of municipal or industrial wastes or injection of other fluids for storage or disposal to the subsurface environment could result in serious pollution of water supplies or other environmental hazards.

(3) The effects of subsurface injection and the fate of injected materials are uncertain with today's knowledge and could result in serious pollution or environmental damage requiring complex and costly solutions on a long-term basis.

Policy and program guidance. To ensure accomplishment of the subsurface protection goals established above it is the policy of the Environmental Protection Agency that:

(1) The EPA will oppose emplacement of materials by subsurface injection without strict controls and a clear demonstration that such emplacement will not interfere with present or potential use of the subsurface environment, contaminate ground water resources or otherwise damage the environment.

(2) All proposals for subsurface injection should be critically evaluated to determine that:

(a) All reasonable alternative measures have been explored and found less satisfactory in terms of environmental protection;

(b) Adequate preinjection tests have been made for predicting the fate of materials injected;

(c) There is conclusive technical evidence to demonstrate that such injection will not interfere with present or potential use of water resources nor result in other environmental hazards;

(d) The subsurface injection system has been designed and constructed to provide maximal environmental protection;

(e) Provisions have been made for monitoring both the injection operation and the resulting effects on the environment;

(f) Contingency plans that will obviate any environmental degradation have been prepared to cope with all well shut-ins or any well failures;

(g) Provision will be made for supervised plugging of injection wells when abandoned and for monitoring to ensure continuing environmental protection.

(3) Where subsurface injection is practiced for waste disposal, it will be recognized as a temporary means of disposal until new technology becomes available enabling more assured environmental protection.

(4) Where subsurface injection is practiced for underground storage or for recycling of natural fluids, it will be recognized that such practice will cease or be modified when a hazard to natural resources or the environment appears imminent.

(5) The EPA will apply this policy to the extent of its authorities in conducting all program activities, including regulatory activities, research and development, technical assistance to the States, and the administration of the construction grants, State program grants, and basin planning grants programs and control of pollution at Federal facilities in accordance with Executive Order 11752.

WILLIAM D. RUCKELSHAUS,
Administrator.

FEBRUARY 6, 1973.

RECOMMENDED DATA REQUIREMENTS FOR ENVIRONMENTAL EVALUATION OF SUBSURFACE EMPLACEMENT OF FLUIDS BY WELL INJECTION

The Administrator's Decision Statement No. 5 on subsurface employment of fluids by well injection has been prepared to establish the Agency's position on the use of this disposal and storage technique. To aid in implementation of the policy a recommended data base for environmental evaluation has been developed.

The following parameters describe the information which should be provided by the injector and are designed to provide regulatory agencies sufficient information to evaluate the environmental acceptability of any proposed well injection. A potential injector should initially contact the regulatory authority to determine the preliminary investigative and data requirements for a particular injection well as these may vary for different kinds of injection operations. The appropriate regulatory authority will specify the exact data requirements on a case by case basis.

(a) An accurate plat showing location and surface elevation of proposed injection well site, surface features, property boundaries, and surface and mineral ownership at an approved scale.

(b) Maps indicating location of water wells and all other wells, mines or artificial penetrations, including but not limited to oil and gas wells and exploratory or test wells, showing depths, elevations and the deepest formation penetrated within twice the calculated zone of influence of the proposed project. Plugging and abandonment records for all oil and gas tests, and water wells should accompany the map.

(c) Maps indicating vertical and lateral limits of potable water supplies which would include both short- and long-term variations in surface water supplies and subsurface aquifers containing water with less than 10,000 mg/l total dissolved solids. Available amounts and present and potential uses of these waters, as well as projections of public water supply requirements must be considered.

(d) Descriptions of mineral resources present or believed to be present in area of project and the effect of this project on present or potential mineral resources in the area.

(e) Maps and cross sections at approved scales illustrating detailed geologic structure and a stratigraphic section (including formations, lithology, and physical characteristics) for the local area, and generalized maps and cross sections illustrating the regional geologic setting of the project.

(f) Description of chemical, physical, and biological properties and characteristics of the fluids to be injected.

(g) Potentiometric maps at approved scales and isopleth intervals of the proposed injection horizon and of those aquifers immediately above and below the injection horizon, with copies of all drill-stem test charts, extrapolations, and data used in compiling such maps.

(h) Description of the location and nature of present or potentially useable minerals from the zone of influence.

(i) Volume, rate, and injection pressure of the fluid.

(j) The following geological and physical characteristics of the injection interval and the overlying and underlying confining beds should be determined and submitted:

(1) Thickness;
(2) areal extent;
(3) lithology;
(4) grain mineralogy;
(5) type and mineralogy of matrix;
(6) clay content;
(7) clay mineralogy;
(8) effective porosity (including an explanation of how determined);
(9) permeability (including an explanation of how determined);
(10) coefficient of aquifer storage;
(11) amount and extent of natural fracturing;
(12) location, extent, and effects of known or suspected faulting indicating whether faults are sealed, or fractured avenues for fluid movement;
(13) extent and effetcs of natural solution channels;
(14) degree of fluid saturation;
(15) formation fluid chemistry (including local and regional variations);
(16) temperature of formation (including an explanation of how determined);
(17) formation and fluid pressure (including original and modifications resulting from fluid withdrawal or injection);
(18) fracturing gradients;
(19) diffusion and dispersion characteristics of the waste and the formation fluid including effect of gravity segregation;
(20) compatibility of injected waste with the physical, chemical and biological characteristics of the reservoir; and
(21) injectivity profiles.

(k) The following engineering data should be supplied:

(1) Diameter of hole and total depth of well;
(2) type, size, weight, and strength, of all surface, intermediate, and injection casing strings;
(3) specifications and proposed installation of tubing and packers;
(4) proposed cementing procedures and type of cement;
(5) proposed coring program;
(6) proposed formation testing program;
(7) proposed logging program;
(8) proposed artificial fracturing or stimulation program;
(9) proposed injection procedure;
(10) plans of the surface and subsurface construction details of the system including engineering drawings and specifications of the system (including but not limited to pumps, well head construction, and casing depth);
(11) plans for monitoring including a multipoint fluid pressure monitoring system constructed to monitor pressures above as well as within the injection zones; description of annular fluid; and plans for maintaining a complete operational history of the well;
(12) expected changes in pressure, rate of native fluid displacement by injected fluid, directions of dispersion and zone affected by the project;
(13) contingency plans to cope with all shut-ins or well failures in a manner that will obviate any environmental degradation.

(l) Preparation of a report thoroughly investigating the effects of the proposed subsurface injection well should be a prerequisite for evaluation of a project. Such a statement should include a thorough assessment of: (1) the alternative disposal schemes in terms of maximum environmental protection; (2) projection of fluid pressure response with time both in the injection zones and overlying formations, with particular attention to acquifers which may be used for fresh water supplies in the future; and (3) problems associated with possible chemical interactions between injected wastes, formation fluids, and mineralogical constituents.

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APPENDIX B

ABBREVIATIONS

ADA -- anthroquinone disulfonic acid
acre-ft -- acre-feet
atm -- atmosphere
bbl -- barrels
BLM -- U.S. Bureau of Land Management
BTU -- British Thermal Unit
°C -- degrees Celsius
cal -- calorie
cm -- centimeter
cu -- cubic
db -- decibel
DOE -- Department of Energy (formerly ERDA)
ERDA -- U.S. Energy Research and Development Administration (presently DOE)
EPA -- U.S. Environmental Protection Agency
°F -- degrees Fahrenheit
ft -- feet
gal -- gallons
GEAP -- Geothermal Environmental Advisory Panel (part of USGS)
gpm -- gallons per minute
gr/gal -- grains per gallon
GRO -- Geothermal Resources Operational Orders (issued by USGS)
ha -- hectare
hr -- hour
in -- inch
J -- joule
kg -- kilogram
KGRA -- Known Geothermal Resource Area
km -- kilometer
kPa -- kilopascal (SI unit of pressure)
kW -- kilowatt
kWh -- kilowatt-hour
LASL -- Los Alamos Scientific Laboratory
L-L -- Langelier-Ludwig (type of geochemical diagram)
LLL -- Lawrence Livermore Laboratory
l -- liter
lb -- pound
lpm -- liter per minute

m -- meter
mg/l -- milligram per liter
mi -- mile
mm -- millimeter
MPa -- megapascal (SI unit of pressure)
mR -- milliroentgen
MW -- megawatt
MWe -- megawatt (electricity)
pCi/l -- picocurie per liter
ppm -- parts per million
psi -- pounds per square inch
SDWA -- Safe Drinking Water Act
sec -- second
SUICP -- State Underground Injection Control Program
sq -- square
TDS -- total dissolved solids
USGS -- U.S. Geological Survey
USPHS -- U.S. Public Health Service

APPENDIX C

U.S.-METRIC CONVERSION TABLE

U.S. CUSTOMARY	U.S. EQUIVALENT	METRIC EQUIVALENT
	Length	
inch (in)	0.083 ft	25.4 millimeters (mm)
foot (ft)	0.33 yd, 12 in	0.3048 meters (m)
yard (yd)	3 ft, 36 in	0.9144 m
mile (mi)	5,280 ft, 1,760 yd	1.609 kilometers (km)
	Area	
square foot (sq ft)	144 sq in	0.0929 square meters (sq m)
square yard (sq yd)	1,294 sq in, 9 sq ft	0.836 sq m
acre	43,560 sq ft, 4,840 sq yd	4,047 sq m, 0.404 hectare (ha)
square mile (sq mi)	640 acres	2.59 square kilometers (sq km)
	Volume	
gallon	4 quarts	3.785 liters (l)
cubic yard (cu yd)	27 cu ft	7.645 cubic meters (cu m)
cubic mile (cu mi)		4.1655 cubic kilometers (cu km)
	Flow Rate	
gallons per minute (gpm)		3.785 liters per minute (lpm), 6.309×10^{-5} cu m/sec
18.2 gpd/sq ft (for water at 60°F)	darcy	9.66×10^{-4} cm/sec (for water at 20°C)
pounds per hour		1.260×10^{-4} kg/sec
cu ft per sec (cfs)		28.32 lps, 0.02831 cu m/sec
	Miscellaneous	
°F = 1.8°C + 32		°C = (°F - 32)5/9
pounds per square inch (psi)		6.889 kilopascals (kPa)
British Thermal Unit (BTU)		1,055 joules (J), 252 (gram) calories
BTU/lb		2,325.84 J/kg
pound (lb)		0.4536 kilogram (kg)
ton		0.907 metric ton
MWe·centuries	3.33 MWe·30 yrs	